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PROGRESS ENERGY LTD. IS A JUNIOR CRUDE OIL AND NATURAL GAS EXPLORATION AND PRODUCTION COMPANY HEADQUARTERED IN CALGARY, ALBERTA, CANADA. ■ THE COMPANY WAS RECAPITALIZED IN 2001 AND A NEW MANAGEMENT TEAM WAS PUT IN PLACE. ■ THE COMPANY'S FIRST YEAR ACCOMPLISHMENTS WERE SIGNIFICANT AND IT IS NOW WELL POSITIONED TO ACHIEVE STRONG GROWTH OVER THE COMING YEARS.

PROGRESS PROMOTES A FAST PACED, TEAM-ORIENTED WORK ENVIRONMENT WHICH WILL CONTRIBUTE TO THE ACHIEVEMENT OF AMBITIOUS GROWTH PLANS. ■ THE COMPANY FOCUSES ON NATURAL GAS AND LIGHT OIL PROJECTS, PLACING STRONG EMPHASIS ON EFFICIENT DISCOVERY AND PRODUCTION OF RESERVES YIELDING LONG TERM PROFITABLE GROWTH.

THE ANNUAL GENERAL AND SPECIAL MEETING OF SHAREHOLDERS WILL TAKE PLACE ON WEDNESDAY, MAY 14, 2003 AT 10:00 A.M. LOCAL TIME AT THE METROPOLITAN CENTRE, 333 4TH AVENUE S.W. CALGARY, ALBERTA. ■ ALL SHAREHOLDERS ARE INVITED TO ATTEND OR SUBMIT THEIR FORM OF PROXY.

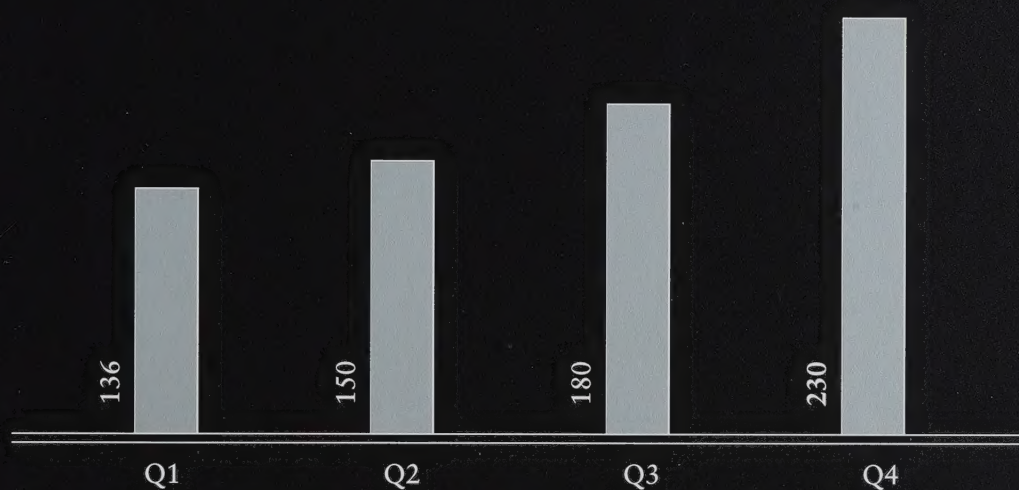
PROGRESS IS LISTED ON THE TORONTO STOCK EXCHANGE, SYMBOL PGX.

PROGRESS ENERGY
HIGHLIGHTS
OF THE YEAR'S RESULTS

		2002	2001	% Change
Operations	Production			
	Crude oil (<i>bbls/d</i>)	1,736	1,812	(4)
	Natural gas liquids (<i>bbls/d</i>)	171	37	362
	Natural gas (<i>mcf/d</i>)	16,327	7,027	132
	Total (<i>boe/d</i>)	4,628	3,020	53
	Proven Reserves			
	Crude oil and NGL (<i>mbbls</i>)	4,871	3,958	23
	Natural gas (<i>mmcf</i>)	71,645	21,581	232
	Total (<i>mboe</i>)	16,812	7,551	123
Financial	(<i>\$ thousands</i>)			
	Cash flow from operations	24,020	17,916	34
	Net earnings	3,444	5,655	(39)
	Capital spending	101,000	25,419	297
	Net debt	47,319	17,916	164
	Shareholders' equity	89,553	40,964	119

Advisory – Certain information regarding the Company set forth in this document, including management's assessment of the Company's future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

PROGRESS HAS THE TEAM
AND THE BUSINESS PLAN IN PLACE
THAT WILL CREATE EFFICIENT
GROWTH ON A
PER SHARE BASIS



2002 QUARTERLY PRODUCTION
(boe per day per million shares)

As we reflect upon our first year in business, our immediate focus is the production and reserve growth that resulted from our efforts during 2002. It is, however, important to come back to the vision and the plan that we entered 2002 both believing in and communicating to our shareholders and staff. We discussed the maturing Western Canadian Sedimentary Basin, the consolidation of the industry and the significant opportunity that has been created for junior companies led by experienced management teams. We set our sights on building a team, establishing dominant positions in at least two growth areas and getting to the job of creating value.

PROGRESS' FIRST FULL YEAR

ACCOMPLISHMENTS

CREATED OPPORTUNITY FOR 2003

We are proud of our accomplishments in our first year. Year end production increased 70 percent on a per share basis, established reserves increased 67 percent on a per share basis while net asset value per share increased 71 percent.

Entering 2002 Progress had a solid production base but limited upside as measured by undeveloped land in strategic areas and drillable prospects. In less than one year the new Progress staff has focussed the Company in two new high potential areas and developed more than 18 months of future drilling opportunities.

This achievement was made possible by a few key initiatives during the year. In the first quarter we executed two large area farmins in central Alberta totalling 70,000 acres of option land. In the second quarter we acquired Campion Resources Ltd. providing core area entry points in Fort St. John, British Columbia as well as central Alberta. During the third quarter we acquired non-core assets from Calpine Canada via Pengrowth Corporation and entered into a farmin on some 30,000 acres of undeveloped land, further building our position in Fort St. John, British Columbia. As well, in the second half of the year, drilling activities on farmin lands in central Alberta and a new drilling program were underway in both new core areas.

PROPERTY ACQUISITIONS ARE

EXPANDING

THE OPERATING BASE AND LOCAL DOMINANCE

Each of these transactions were very important for Progress, building local dominance, exploration and exploitation inventory and providing the opportunity to generate meaningful reserve and production additions during the second half of the year.

The combination of acquisitions and drilling proved very effective from both a pace of growth and efficiency perspective. 2002 reserve additions of 13.2 million equivalent barrels more than doubled our reserve base and replaced annual production by 7.8 times.

Fort St. John, British Columbia

This new core growth area is the result of 2002 initiatives that saw; the acquisition of Campion Resources Ltd. in June 2002 providing the entry point into this area, the acquisition of various other assets in the Fort St. John area in October 2002 giving Progress a dominant position in the area and various acquisitions of neighbouring assets and crown land during the year.

Five wells drilled in 2002 resulted in three natural gas wells and one oil well. At December 31, 2002 the Company controlled 95,000 acres of undeveloped land with a drilling inventory that will lead to approximately 15 wells drilled during 2003. During Q4 2002 this area produced approximately 2,218 boe per day.

Gilby, West Central Alberta

Two significant farmins with royalty trusts provided the initial land capture in the area and resulted in a dominant position. Various acquisitions of neighbouring assets, the merging of six 3D seismic data sets covering 75 square miles and the acquisition of crown and freehold land added to the position. During the second half of 2002 the Company drilled

eight wells resulting in seven natural gas wells. The Company now controls over 100,000 acres of undeveloped land and has an identified drilling inventory that will support a continuous program through the third quarter of 2003. During Q4 2002 this area produced approximately 1,206 boe per day.

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Exploration generated established reserve additions represented one-third of total additions and resulted in finding and development costs of \$6.83 per barrel equivalent on expenditures of \$30.4 million. Acquisitions completed during the year accounted for 8.7 million equivalent barrels of established reserves and 100,000 acres at an all-in cost of \$8.07 per barrel equivalent after the investment of \$70.6 million. Production growth continued throughout 2002 and by the fourth quarter had grown by 119 percent over the same period last year. The cost of the production growth associated with drilling successes was approximately \$15,000 per daily flowing barrel equivalent while our acquired assets resulted in production

A PLAN BASED ON CORE AREA DOMINANCE IS

ADVANCING

PROGRESS' GROWTH TARGETS

addition costs of approximately \$23,000 per barrel equivalent per day. We consider the metrics of our 2002 acquisition program to be good given the importance of establishing our operating presence in our focus areas and the significant undeveloped land position included. The efficiencies related to the year's exploration efforts are well in the range of our targeted objectives and are considered representative of future costs.

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During 2002 the Company transformed the asset base into two new core areas. These areas have the attributes that we believe will result in efficient growth. They are medium depth — generally in the 1,000 to 2,500 meters range — with multi-zone potential, high netbacks, year-round access and good infrastructure. The Company has built a dominant position in these areas and has the technical confidence to translate the potential to meaningful growth and develop the potential.

We believe that Progress is the right size to execute and take advantage of the smaller yet very profitable exploration targets that are more prevalent today in the Western Canadian Sedimentary Basin. The fast paced target-oriented workplace that we have established at Progress is a distinct advantage as we compete for opportunities.

Timing and allocation of capital are arguably the most important controllables in a company's success. During periods of low commodity prices, such as early 2002, we tend to collect inventory through acquisitions at economic parameters while in periods of high commodity prices, as currently being experienced, we will drill and harvest our internal inventory developing balance sheet strength.

PACE OF ACTIVITY AND ALLOCATION OF
CAPITAL DECISIONS ARE **BALANCED**
FOR EFFECTIVE GROWTH

The balancing of capital exposure with respect to commodity mix, geography and risk profile is fundamental to a successful project portfolio. The opportunity depth present within Progress today provides such a program for 2003.

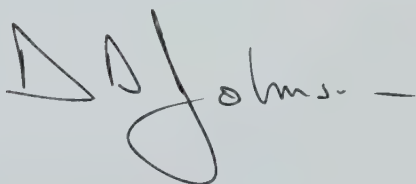
At the time of this writing commodity prices are strong and the potential exists for Progress to exceed budgeted cash flow. The Company's practice of continuously monitoring spending opportunities will allow for increased capital program.

Our objective is to build a quality company. We define quality in assets by concentration, efficiency and potential.

We also recognize the need for quality as it relates to ingenuity and diligence with respect to our investments and operations while continued effort is dedicated to timely and complete reporting to our shareholders. Achievement of all of these attributes is every employee's goal. We feel that 2002 has been a great start in building such a quality company.

ASSET QUALITY IS DEFINED BY
C O N C E N T R A T I O N ,
EFFICIENCY AND POTENTIAL

The Company is well positioned to deliver cost efficient growth and is excited about its 2003 prospects. On behalf of the Board of Directors I would like to recognize the efforts of the entire Progress team in the delivery of an outstanding year.

A handwritten signature in black ink, appearing to read "D.D. Johnson", followed by a horizontal line.

David D. Johnson
President and CEO

March 14, 2003



THE PROGRESS TEAM

From Left to Right

Michael R. Culbert
*Vice President Marketing and
Business Development*

Neil H. Samis
Vice President Production

David D. Johnson
*President and
Chief Executive Officer*

William J. Lewington
Controller

Steven A. Allaire
*Vice President Finance and
Chief Financial Officer and
Corporate Secretary*

Edward J. Kalchoff
Vice President Land

Daniel C. Topolinsky
Vice President Exploration

PROGRESS ENERGY

03 PLANS

During 2002 Progress was successful in the creation of two new high quality growth areas, Fort St. John, British Columbia and West Central Alberta. The Company has assembled over 230,000 net acres of undeveloped land and established a strong exploration momentum with its 2002 drilling results. We enter 2003 with a large and balanced inventory of drillable prospects split between light oil and natural gas.

As a result of the successful drilling program and the Fort St. John asset acquisition the Company exited 2002 at over 7,000 boe per day. The Company is forecasting average 2003 production of approximately 8,000 boe per day with an exit production rate for 2003 of approximately 9,000 boe per day. The Company prepared its budget in November 2002. Its commodity price assumptions are reflected in the table below. In the current price environment these budgeted prices appear conservative. The table below provides alternative pricing assumptions using our base capital budget and forecasted production levels.

2003 Cash Flow per Share
(\$/share)

		NYMEX (US\$/mmbtu)		
		3.75	4.75	5.75
WTI (US\$/bbl)	31	1.62	1.93	2.24
	27	1.51	1.82	2.13
	23	1.40	1.71	2.02

■ Progress budgeted price

The Company's 2003 capital program is \$50 million with \$11 million slated for land and seismic, \$28 million on drilling and \$11 million on facilities. The program will result in the drilling of approximately 55 to 60 wells.

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Management's Discussion and Analysis

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis is provided by the management of Progress Energy Ltd. and should be read in conjunction with the financial statements presented in this annual report.

BOE PRESENTATION

For the purposes of calculating unit costs, natural gas is converted to a barrel equivalent ("BOE") using six thousand cubic feet equal to one barrel unless otherwise stated. This conversion conforms with the Canadian Securities Regulators proposed National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities. BOE's are very approximate comparative measures that, in some cases, could mislead, particularly if used in isolation.

2002 HIGHLIGHTS

Campion Resources Ltd. Acquisition

- On April 15, 2002 Progress announced that it had entered into an agreement whereby Progress would offer to purchase all of the issued and outstanding common shares of Campion Resources Ltd. ("Campion"). The consideration offered was 0.40 of a Progress common share for each Campion common share. On June 3, 2002, Progress acquired all of the outstanding shares of Campion and issued 3,634,770 common shares.
- The Campion acquisition established an entry point into the new core area of Fort St. John, British Columbia and contributed to the growth of the central Alberta area.
- The acquisition provided the Company with a strategic growth platform with existing operations and good land positions, which could be successfully and aggressively developed into key operating areas.
- Proven reserves were 4.2 million barrels of oil equivalent ("boe" computed on a 6 mcf to 1 boe basis), including 22.6 bcf of natural gas reserves and 400,000 bbls of crude oil and natural gas liquids.
- Production was approximately 1,600 boe per day, including 8,800 mcf per day of natural gas production and 130 bbls of crude oil and natural gas liquids per day. Over 85 percent of the production is operated with an average working interest of 80 percent.
- The acquisition also provided undeveloped land of over 63,000 net acres.
- The Company recorded goodwill of \$9.0 million on the transaction.
- The results of operations for the 12 months ended December 31, 2002 include the results of Campion Resources Ltd. from June 3, 2002.

Fort St. John, British Columbia Asset Acquisition

- On September 19, 2002 Progress announced that it had entered into an agreement whereby Progress would acquire certain properties in the Fort St. John area of northeast British Columbia for a purchase price of approximately \$26 million including adjustments. The acquisition closed on October 4, 2002 and was subject to adjustments to July 1, 2002.
- The acquisition consisted of various producing properties in the Fort St. John area that had a combined total production of approximately 1,000 boe per day, consisting of 4,000 mcf per day of natural gas and 330 bbls per day of crude oil and natural

gas liquids. Reserves associated with this acquisition were approximately 3.0 million boe of proven reserves, consisting of 13.5 bcf of natural gas and 741,000 bbls of crude oil and natural gas liquids.

- The acquisition included 61,000 acres of undeveloped land with Progress and the vendor each owning a 50 percent working interest. Progress acquired 30,500 net acres and has access to the complementary vendor-owned 30,500 net acres through a farmin arrangement. Progress has committed to gross expenditures of \$10 million on the joint lands over the 18 month period beginning October 1, 2002.
- The acquisition, combined with the acquisition of Champion Resources Ltd. in June 2002, solidified Progress' position in the Fort St. John area of northeast British Columbia. The acquisition provided Progress with a production platform, infrastructure and an undeveloped land position that will facilitate strong growth for the next several years. The acquisition was consistent with the Company's strategy of building core area dominance in the identified focus areas of Fort St. John and west central Alberta.
- The results of operations for the 12 months ended December 31, 2002 include the results of the Fort St. John asset acquisition from October 4, 2002.

Financings

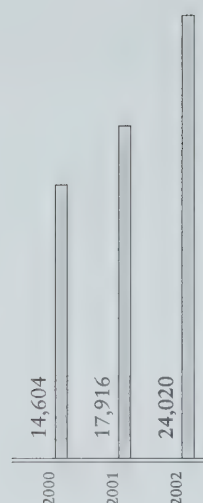
- The Fort St. John, British Columbia acquisition was funded by a bought deal private placement of 4,464,300 common shares at a price of \$5.60 per common share for total gross proceeds of \$25 million. The financing closed on October 1, 2002.

Reserves

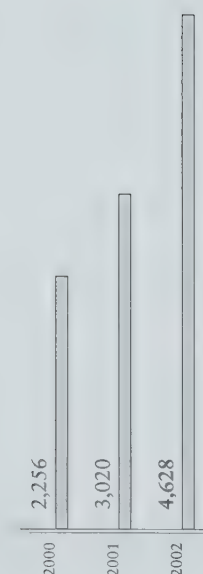
- Total proven reserves at December 31, 2002 increased 121 percent to 16.8 million boe compared to 7.6 million boe in 2001.
- Total proven plus probable reserves at December 31, 2002 increased 139 percent to 22.5 million mboe compared to 9.4 million boe in 2001.
- Finding and development costs associated with the total 2002 capital expenditures and the total 2002 reserve growth were \$9.22 per proven boe and \$6.82 per proven plus probable boe.
- Finding and development costs related to the exploration and development program were \$8.16 per proven boe and \$5.88 per proven and probable boe. After taking into account revisions from prior periods the finding and development cost related to the exploration and development program was \$8.95 per proven boe and \$6.22 per proven and probable boe.
- Finding and development costs related to the 2002 acquisitions were \$9.35 per proven boe and \$7.11 per proven and probable boe.

Operations

- Average 2002 production increased 53 percent to 4,628 boe per day compared to 3,020 boe per day in 2001.
- Average 2002 fourth quarter production averaged 7,096 boe per day compared to 3,233 boe per day on 2001, an increase of 119 percent.
- Crude oil and liquids production increased three percent to 1,907 bbls per day compared to 1,849 bbls per day in 2001.



CASH FLOW
(\$ thousands)



TOTAL PRODUCTION
(boe per day)

- Natural gas production increased 132 percent to 16,327 mcf per day compared to 7,027 mcf per day in 2001.
- The cost associated with this production growth during 2002 was \$20,257 per flowing boe.

Financial

- Revenue increased 38 percent to \$45.8 million compared to \$33.2 million in 2001.
- Cash flow increased 34 percent to \$24.0 million (\$0.93 per share) from \$17.9 million in 2001 (\$0.98 per share).
- Net earnings for the year ended December 31, 2002 were \$3.4 million (\$0.13 per share) compared to \$5.7 million (\$0.31 per share) in 2001.
- Net capital expenditures totalled \$101.0 million in 2002 (including \$40.8 million for the acquisition of Campion Resources Ltd.) compared to \$25.4 million on 2001.
- Total net debt was \$47.3 million at December 31, 2002 compared to \$17.4 million at the same time in 2001. The increase in total debt is a result of the increase in 2002 exploration and development activity and net debt assumed on the acquisition of Campion Resources Ltd.
- The Company had 30,911,781 common shares outstanding at December 31, 2002 compared to 22,087,398 common shares outstanding at December 31, 2001. This increase is the result of 3,634,770 common shares issued pursuant to the acquisition of Campion Resources Ltd., the issuance of 4,464,300 common shares on a private placement basis pursuant to the acquisition of the Fort St. John, British Columbia assets and 725,313 issued on the exercise of stock options.

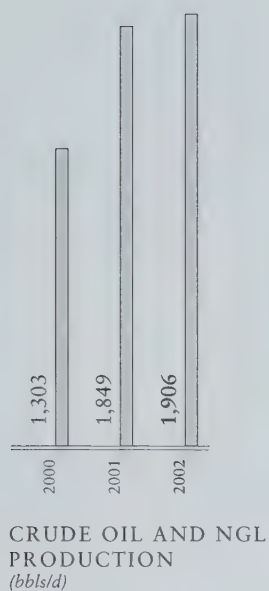
PRODUCTION

Average 2002 production increased 53 percent to 4,628 boe per day compared to 3,020 boe per day in 2001 while 2002 fourth quarter production averaged 7,096 boe per day.

Production Summary

	Fourth Quarter 2002	2002	2001	2000
Annual Production				
Crude oil (bbls)	189,020	633,335	661,556	464,700
Natural gas liquids (bbls)	31,338	62,532	13,402	12,352
Natural gas (mcf)	2,594,844	5,959,438	2,564,720	2,092,678
Total equivalent (boe)	652,832	1,689,107	1,102,411	825,832
Daily Production				
Crude oil and liquids (bbls/d)	2,055	1,736	1,812	1,270
Natural gas liquids (bbls/d)	340	171	37	33
Natural gas (mcf/d)	28,205	16,327	7,027	5,718
Total equivalent (boe/d)	7,096	4,628	3,020	2,256

Crude oil production for the year decreased four percent to 1,736 bbls per day from 1,812 bbls per day in 2001. This decrease in production was largely due to production declines in Two Creek, Alberta and Saskatchewan and limited focus on crude oil drilling activity.



Natural gas liquids increased during the year to 171 bbls per day compared to 37 bbls per day in 2001. This increase was the result of higher natural gas liquids content in the Company's new areas of west central Alberta and Fort St. John, British Columbia.

Natural gas production increased 132 percent to 16,327 mcf per day in 2002 from 7,027 mcf per day in 2001. The increase in natural gas volumes was due to the two natural gas focused acquisitions during the year and the successful 2002 exploration and development program in west central Alberta and Fort St. John core areas.

Production Reconciliation

	Production Equivalent (boe/d)
Production fourth quarter 2001	3,233
Decline on base production	(808)
Exploration program production additions during 2002	2,286
Decline on new 2002 production	(115)
2002 Acquisitions	2,700
Decline on 2002 acquisitions	(200)
Production fourth quarter 2002	7,096

Cost of Production Additions

During 2002 the Company added approximately 4,986 boe per day of new production from both its core exploration and development activities and its acquisition initiatives. In a total capital expenditure program of \$101.0 million this resulted in production being added at a cost of \$20,257 per boe per day.

Key Producing Areas

The following table summarizes the Company's average production for the years ended December 31, 2002, 2001 and 2000 for Progress' key producing areas.

Principal Producing Properties (boe/d)

	Fourth Quarter 2002	2002	2001	2000
Fort St. John, British Columbia	2,218	759	-	-
Milo, British Columbia	503	579	624	322
Total British Columbia	2,721	1,338	624	322
West Central Alberta	1,206	510	-	-
East Central Alberta	574	282	-	-
North Alberta, Two Creek	1,296	1,269	1,117	617
North Alberta, Other	502	357	218	392
Total Alberta	3,578	2,418	1,335	1,009
Southeast Saskatchewan/Manitoba	797	872	1,061	925
Total	7,096	4,628	3,020	2,256

The Fort St. John, British Columbia area evolved during 2002 as a result of the acquisition of Campion Resources Ltd, the acquisition of the Fort John area assets and exploration and development activities. The west central Alberta assets are the result of 2002 activities including two large regional farmins and an active exploration and development program during the second half of the year. The east central Alberta assets are the result of the Campion Resources Ltd. acquisition and a successful workover and recompletion program undertaken subsequent to the closing of the acquisition.

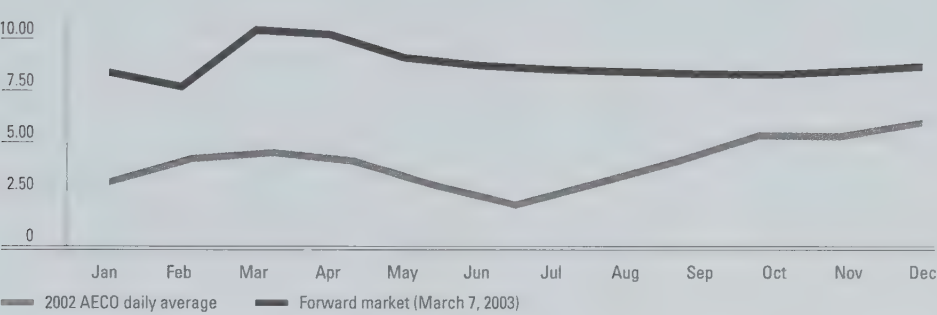
COMMODITY PRICING

	2002	2001	2000
Crude oil <i>(before hedging - \$/bbl)</i>	33.72	31.83	40.88
Hedging <i>(\$/bbl)</i>	(3.14)	(0.09)	(0.41)
Unrealized loss on financial instrument	(0.59)	-	-
Crude oil <i>(after hedging - \$/bbl)</i>	29.99	31.74	40.47
Natural gas liquids <i>(before hedging - \$/bbl)</i>	32.08	35.30	39.22
Hedging <i>(\$/bbl)</i>	-	-	-
Natural gas liquids <i>(after hedging - \$/bbl)</i>	32.08	35.30	39.22
Natural gas <i>(before hedging - \$/mcf)</i>	4.06	4.59	5.11
Hedging <i>(\$/mcf)</i>	0.04	(0.02)	(0.19)
Amortization of commodity sales contract <i>(\$/mcf)</i>	0.07	-	-
Natural gas <i>(after hedging - \$/mcf)</i>	4.17	4.57	4.92

The commodity prices recorded above are net of the effects of commodity price hedging charges of \$1.8 million (\$0.1 million in 2001 and \$0.6 million in 2000) and the amortization of a commodity sales contract of (\$0.4) million (nil in 2001 and 2000) for the year ended December 31, 2002. The amortization of commodity sales contract relates to a physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. At the time of the acquisition the fair value of the contract was a liability of \$4.1 million. This value was recorded as a liability and is being amortized over the life of the contract. The unrealized loss on financial instrument relates to a written crude oil call option for the first quarter of 2003 that does not qualify for hedge accounting. The change in the call option's fair value to December 31, 2002 has been charged to petroleum and natural gas revenue.

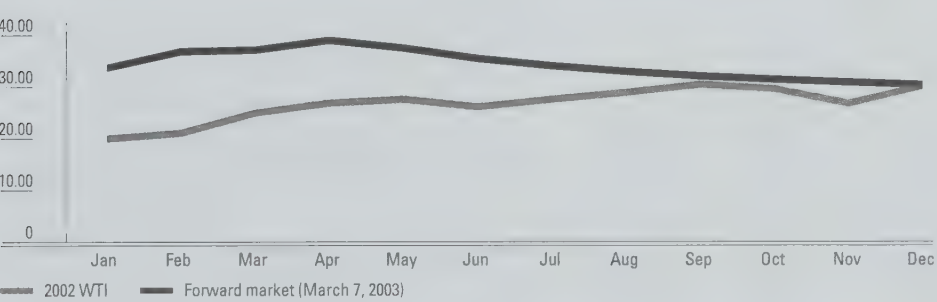
Middle East tensions over-shadowed much of 2002 causing a war premium on crude oil. As a result, OPEC set quotas and called for closer compliance from members to support prices within the desired OPEC basket price range. Although overproduction continued, OPEC held the quotas in place until the Venezuelan unrest caused a significant supply shortage. US oil stocks are now at 28 year lows as the likelihood of war with Iraq seems imminent. As can be seen in the graph that follows the forward market is extremely strong and steeply backwardated as the war premium and supply crunch are discounted over the year.

AECO Natural Gas Prices
CDN\$/gj



During 2002 North American natural gas prices were extremely volatile. Due to mild weather and ample gas storage levels, prices in the early part of 2002 were weaker than previous winters. As spring approached modest storage injections and low rig counts provided price support. Western Canadian prices dropped significantly in the summer of 2002 as pipeline maintenance coupled with excess hydro capability in the Pacific Northwest reduced capacity as well as demand. During the fall buoyant crude oil prices and continuation of modest storage injections provided for strong Alberta prices that peaked close to \$6.00 per gj in December. Prices in 2003 have continued from this historically high level. Persistently cold weather has resulted in record storage withdrawals week after week. Demand for storage re-injection is forecast to support prices throughout the summer and fall of 2003 as can be seen from the current forward price curve illustrated in the graph below.

WTI Crude Oil Prices
US\$/bbl



Crude Oil Pricing

West Texas Intermediate (“WTI”) is the benchmark for North American oil prices and is the crude type against which the NYMEX futures contract is priced. Canadian crude oil prices are based upon refiners’ postings at Alberta hubs like Edmonton and Hardisty or Taylor, British Columbia and Cromer in Manitoba. These refiners’ postings represent the WTI price at Cushing, Oklahoma less a transportation differential, the Canadian/US foreign exchange rate, adjustments for relative quality and, to some extent, an adjustment for regional market conditions.

Progress’ average field prices reflect the refiners’ posted price at the market centers less deductions for transportation from the field and adjustments for Progress’ product quality relative to the posted product. Progress’ average Alberta field price in 2002 was \$29.59 per bbl versus \$39.61 for the average of the light sweet postings at Edmonton, Alberta. In the latter part of 2002 Progress added crude oil and liquids production in British Columbia. The 2002 British Columbia average oil price for Progress was \$39.43 per bbl for its light oil compared to the B.C. light posting of \$41.38 per bbl for the year. For Saskatchewan and Manitoba, Progress’ average field price in 2002 was \$36.15 per bbl versus \$37.19 per bbl for the average of the light sweet blend postings at Cromer, Manitoba.

Overall Progress crude oil was 40 percent light crude and 60 percent medium. This quality resulted in minimal adjustments from the stream prices.

Crude Oil Production and Prices by Province

	2002		2001		2000	
	bbl/d	\$/bbl	bbl/d	\$/bbl	bbl/d	\$/bbl
Alberta	726	29.59	772	28.65	358	36.14
British Columbia	163	39.43	n/a	n/a	n/a	n/a
Saskatchewan and Manitoba	847	36.15	1,040	34.19	912	42.75
Total production and average sales price ⁽¹⁾	1,736	33.72	1,812	31.83	1,270	40.88

(1) Excludes hedging gains or losses

Alberta Crude Oil Prices

	2002	2001	2000
WTI (US\$/bbl at Cushing, Oklahoma)	26.08	25.90	30.20
Average exchange rate	1.5703	1.5489	1.4854
WTI (CDN\$/bbl at Cushing Oklahoma)	40.95	40.12	44.86
Less: Differential Cushing, Oklahoma to Edmonton	(1.34)	(0.99)	(0.62)
Edmonton light sweet posting (CDN\$/bbl)	39.61	39.13	44.33
Less: Quality differential & transportation to Edmonton	(10.02)	(10.48)	(8.19)
Progress average field price in Alberta (CDN\$/bbl)	29.59	28.65	36.14

British Columbia Crude Oil Prices

	2002 Q4*
WTI (US\$/bbl at Cushing, Oklahoma)	28.15
Average exchange rate	1.5695
WTI (CDN\$/bbl at Cushing Oklahoma)	44.18
Less: Differential Cushing, Oklahoma to Fort St. John	(2.80)
B.C. light posting (CDN\$/bbl)	41.38
Less: Quality differential & transportation to Fort St. John	(1.95)
Progress average field price in British Columbia (CDN\$/bbl)	39.43

* The majority of the British Columbia crude oil volumes were added in the fourth quarter of 2002, therefore the pricing table has been prepared to compare the fourth quarter of 2002 market prices.

Saskatchewan and Manitoba Crude Oil Prices

	2002	2001	2000
WTI (US\$/bbl at Cushing, Oklahoma)	26.08	25.90	30.20
Average exchange rate	1.5703	1.5489	1.4854
WTI (CDN\$/bbl at Cushing Oklahoma)	40.95	40.12	44.86
Less: Differential cushing, Oklahoma to Cromer	(3.76)	(5.05)	(1.72)
LSB Cromer Posting (CDN\$/bbl)	37.19	35.07	43.14
Less: Quality differential & transportation to Cromer	(1.04)	(0.88)	(0.39)
Progress average field price in Saskatchewan & Manitoba (CDN\$/bbl)	36.15	34.19	42.75

Natural Gas Pricing

US natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta natural gas is referenced off Nova Inventory Transfer (“NIT”) or the AECO Hub and British Columbia natural gas off of Sumas Washington or Station #2 market centers. Virtually all of Progress’ natural gas is sold at market prices at one of the Alberta or British Columbia hubs.

Natural Gas Production and Prices by Province

	2002		2001		2000	
	mcf/d	\$/mcf	mcf/d	\$/mcf	mcf/d	\$/mcf
Alberta	9,367	4.29	3,162	5.47	3,713	5.59
British Columbia	6,806	3.81	3,742	3.95	1,932	4.36
Saskatchewan	154	1.26	123	1.47	73	0.89
Total production and average sales price ⁽¹⁾	16,327	4.06	7,027	4.59	5,718	5.11

(1) Excludes any hedging gains or losses.

Alberta Natural Gas Prices

	2002	2001	2000
NYMEX (US\$/mmbtu calendar month average)	3.37	4.06	4.33
Less: AECO basis differential to Henry Hub (US\$/mmbtu)	(0.77)	(0.54)	(0.59)
AECO (US\$/mmbtu)	2.60	3.52	3.74
Average exchange rate	1.5703	1.5489	1.4854
AECO price (CDN\$/mmbtu daily average)	4.08	5.45	5.56
Less: TCPL Alberta system charges	(0.18)	(0.24)	(0.28)
Variance: Progress pool price vs spot	0.39	0.26	0.31
Progress average Alberta plantgate price (CDN\$/mcf)	4.29	5.47	5.59

British Columbia Natural Gas Prices

	2002	2001	2000
NYMEX (US\$/mmbtu calendar month average)	3.37	4.06	4.33
Less: Sumas basis differential to Henry Hub (US\$/mmbtu)	(0.69)	(0.52)	(0.16)
Sumas (US\$/mmbtu)	2.68	3.54	4.17
Average exchange rate	1.5703	1.5489	1.4854
Sumas price (CDN\$/mmbtu monthly index)	4.21	5.48	6.19
Less: WEI transportation, processing & gathering charge*	(1.30)	(1.35)	(1.30)
Variance: Progress pool price vs spot	0.90	(0.18)	(0.53)
Progress average British Columbia field price (CDN\$/mcf)	3.81	3.95	4.36

* British Columbia has an infrastructure built by Westcoast Energy Inc. (“WEI”) that enables gas producers in that province to avoid facility construction in exchange for regulated gathering, processing and transmission fees.



RISK MANAGEMENT

Progress has a Risk Management Policy approved by the Board of Directors of the Company and adhered to by management. The objective of Progress’ risk management activities is to reduce exposure to decreases in commodity price that would materially impact the cash flow and ultimately affect the growth of the Company. Transactions entered into are typically defensive in nature and of short duration.

In 2002, the Company entered into a number of financial transactions for crude oil and natural gas whereby it bought put options, sold call options or entered into costless collar transactions. For further disclosure of Progress’ financial transactions refer to Note 8, Financial Instruments in the Consolidated Financial Statements.

REVENUE

Revenues from crude oil, liquids and natural gas sales increased by 38 percent to \$45.8 million in 2002 from \$33.2 million in 2001. This increase was the result of a 53 percent increase in oil equivalent production growth (4,628 boe per day in 2002 compared to 3,020 boe per day in 2001), however the production increase was partially offset by a 10 percent decrease in realized commodity prices (\$27.13 per boe in 2002 compared to \$30.12 in 2001).

(\$ thousands)	2002	2001	2000
Crude oil revenue	21,353	21,058	18,998
Hedging charges	(1,988)	(58)	(190)
Unrealized loss on financial instrument	(373)	-	-
Crude oil revenue after hedging charges	18,992	21,000	18,808
Natural gas liquids revenue	2,006	473	485
Hedging charges	-	-	-
Natural gas liquids after hedging charges	2,006	473	485
Natural gas revenue	24,194	11,768	10,691
Hedging charges	628	(39)	(391)
Natural gas revenue after hedging charges	24,822	11,729	10,300
Total revenue	45,820	33,202	29,593
Average price (\$/boe)	27.13	30.12	35.84

ROYALTIES

Royalties increased 46 percent to \$9.0 million in 2002 from \$6.2 million in 2001. The average royalty rate, after recording the effects of hedging charges, increased to 19.7 percent during 2002 compared to 18.6 percent in 2001. The average royalty rate, before recording the effects of hedging charges, increased to 19.0 percent during 2002 compared to 18.6 percent in 2001.

<i>(\$ thousands)</i>	2002	2001	2000
Royalties			
Crown (net of ARTC)	7,082	4,748	4,973
Freehold and other	1,941	1,435	1,878
Net royalties	9,023	6,183	6,851
Total <i>(\$/boe)</i>	5.34	5.61	8.30
Average royalty rate <i>(after impact of hedging charges - %)</i>	19.7	18.6	23.1
Average royalty rate <i>(before impact of hedging charges - %)</i>	19.0	18.6	22.7

Royalties by Product

The following provides a breakdown of royalties by product. Rates are calculated before the impact of hedging activities and ARTC.

	2002	2001	2000
Crude oil royalties	3,063	3,593	3,768
\$/boe	4.84	5.43	8.11
Average crude oil royalty rate (%)	14.3	17.1	19.8
Natural gas royalties	5,984	2,896	2,968
\$/boe	6.02	6.78	8.51
Average natural gas royalty rate (%)	24.7	24.6	27.8
Natural gas liquids royalties	476	194	115
\$/boe	7.61	14.51	9.3
Average natural gas liquids royalty rate (%)	23.7	41.1	23.7

OPERATING EXPENSES

Operating expenses increased 61 percent to \$8.2 million in 2002 from \$5.1 million in 2001. This increase can be attributed to higher production rates achieved by the Company during the year. Operating costs per boe increased six percent to \$4.88 per boe compared to \$4.61 per boe in 2001. This increase is due to the higher operating costs associated with the acquired properties and third party natural gas processing fees related to the additional natural gas production. The fourth quarter of 2002 operating costs averaged \$5.18 per boe. Average operating costs for 2003 are forecasted to be \$5.00 per boe but will be higher in the beginning of the year. The Company is focused on reducing operating costs going forward and it is anticipated that more attention and higher activity in these new core areas will reduce operating costs.

<i>(\$ thousands)</i>	2002	2001	2000
Total operating expenses	8,246	5,084	4,170
\$/boe	4.88	4.61	5.05
Crude oil operating expenses	5,787	4,132	2,994
\$/boe	9.14	6.25	6.44
Natural gas and natural gas liquids operating expenses	2,459	952	1,176
\$/boe	2.33	2.16	3.26

GENERAL AND ADMINISTRATIVE EXPENSES

Gross general and administrative expenses increased 46 percent in 2002 to \$4.5 million from \$3.1 million in 2001. This resulted mainly from the increase in full-time and contract staff required as a result of the increased size of the Company’s operations, the larger asset base and some restructuring costs incurred during the year. The fourth quarter included provisions for annual charges such as annual audit, reserve report, and a provision for 2002 employee bonuses.

The magnitude of operator recoveries is a function of activity levels and degree to which the Company operates its joint venture interests. Progress operates 95 percent of its production and generally operates all of the drilling activity. Operator recoveries for 2002 were \$1.0 million compared to \$1.4 million in 2001. This decrease is primarily a function of the disproportionate impact of one property, drilled in 2001, had on recoveries. Net general and administrative costs increased to \$2.8 million in 2002 from \$1.0 million in 2001. On a boe basis, net general and administrative costs increased 73 percent to \$1.64 for the year from \$0.95 in 2001.

Progress capitalizes general and administrative expenses associated with Company’s exploration and development activities as these expenses are associated with adding reserves versus the cost of producing reserves. During 2002 these costs increased as a result of an increase in the number of employees in the exploration team.

(\$ thousands)	2002	2001	2000
Gross general and administrative	4,467	3,063	2,245
Operator recoveries	(980)	(1,369)	(1,019)
Capitalized expenses	(722)	(648)	(562)
Net general and administrative	2,765	1,046	664
Net general and administrative (\$/boe)	1.64	0.95	0.80

The Company had the following full time employees and full time consultants at year end.

Head office	34	17	15
Field	2	1	1
	36	18	16

FINANCING CHARGES

Bank debt increased to \$43.4 million during 2002 compared to \$18.0 million in 2001 as a result of the increased capital program and the assumption of debt associated with the acquisition of Campion Resources Ltd. Financing charges increased 17 percent to \$1.5 million in 2002 from \$1.3 million in 2001. The increase reflected an increase in average debt levels during the year, however this was partially offset by declining interest rates during 2002.

(\$ thousands)	2002	2001	2000
Financing charges	1,470	1,253	946
Average:			
Cost (\$/boe)	0.87	1.14	1.15
Debt outstanding	32,463	23,590	15,215
Interest rate (%)	4.5	5.3	6.2

DEPLETION AND DEPRECIATION AND SITE RESTORATION
AND ABANDONMENTS

During 2002, depletion and depreciation of capital assets and the provision for site restoration and abandonments increased to \$16.8 million from \$10.0 million in 2001. This increase is largely the result of increased production volumes and higher depletion rates. Depletion and depreciation increased to \$9.97 per boe during 2002 compared to \$9.05 per boe in 2001. Depletion and depreciation is computed quarterly based on estimated reserve additions. During the fourth quarter of 2001 the new reservoir engineers reduced Progress’ proven reserves by assigning more conservative recovery factors to the Company’s major properties. This resulted in a fourth quarter 2001 depletion and depreciation of \$10.67 per boe. The depletion and depreciation per boe has decreased every quarter during 2002 with the fourth quarter of 2002 averaging \$9.36 per boe reflecting the lower finding and development costs attained during the year.

At December 31, 2002 the Company estimated that its future site restoration costs to be accrued over the life of the remaining proved reserves were approximately \$11.8 million compared to \$6.7 million in 2001. This increase is due to increase in well ownership as a result of 2002 drilling activity and acquisitions.

(\$ thousands)	2002	2001	2000
Depletion	15,426	9,078	5,350
Depreciation	143	52	50
Total depletion and depreciation	15,569	9,130	5,400
Provision for site restoration	1,264	845	513
	16,833	9,975	5,913
Depletion and depreciation (\$/boe)	9.97	9.05	7.16
Depletion and depreciation rate (%) ⁽¹⁾	13.5	13.4	11.2

(1) The depletion rate presented above converts reserves and production to equivalent units of oil based on relative energy content consistent with the Company’s accounting policy.

CEILING TEST

In accordance with the Canadian Institute of Chartered Accountants’ full cost accounting guidelines, Progress performs an annual ceiling test calculation using year-end prices. The Company also performs quarterly ceiling test calculations using pricing received for product sales during the last day of each quarter. No write down was required for the year ended December 31, 2002 based on year end commodity prices of \$43.44 per bbl for crude oil and \$5.80 per mcf for natural gas. Based on increased reserves and year-end commodity prices of \$22.94 per bbl for oil and \$2.99 per mcf for natural gas, no write down was required in 2001.

GOODWILL

The Company attributed \$9.0 million of value to goodwill in the acquisition of Campion Resources Ltd. In accordance with Canadian generally accepted accounting principles goodwill is not amortized but is subject to an impairment test. Progress conducts the goodwill impairment test on an annual basis at its fiscal year end. Goodwill may be tested for impairment between annual tests in certain situations. There was no impairment of goodwill as a result of the test conducted at December 31, 2002.

INCOME AND CAPITAL TAXES

Income taxes (future and current) decreased four percent in 2002 to \$3.4 million from \$3.5 million in 2001. Progress' effective tax rate increased to 45.2 percent from 36.5 percent respectively for the above mentioned years. The increase in the effective tax rate was due to certain income tax filing positions taken by the Company relating to Campion Resources Ltd., acquired on June 3, 2002, that were different than what was estimated at the time of acquisition. The Company recorded a current income tax recovery of \$0.4 million during 2002 compared to a current tax expense of \$1.2 million for 2001. Reduced pre-tax income that resulted from lower commodity prices was the main reason for the decrease in total income taxes.

Capital taxes increased in 2002 as compared to 2001. The resource surcharge portion of the Saskatchewan capital tax decreased in 2002 as a result of lower commodity prices. This decrease was partially offset by an increase in federal and provincial capital taxes, which are based upon year end equity and debt levels. The capital taxes increased proportionally with the growth in the balance sheet.

(\$ thousands)	2002	2001	2000
Future income taxes	3,803	2,286	2,821
Current income taxes	(422)	1,238	1,824
Total income taxes	3,381	3,524	4,645
Capital taxes	658	482	534
	4,039	4,006	5,179
Effective tax rate (%)	45.2	36.5	42.0

The Company has approximately \$97.0 million in tax pools to shelter taxable income in future years. The tax pools are as follows:

(\$ thousands)	
Canadian exploration expense	4,800
Canadian development expense	12,900
Canadian oil and gas property expense	48,500
Undepreciated capital cost	20,700
Loss carry-forward	3,800
Other	6,300
	97,000

NET EARNINGS

Net earnings decreased to \$3.4 million in 2002 from \$5.7 million in 2001. Net earnings per boe decreased to \$2.04 in 2002 from \$5.13 in 2001, while cash flow per boe decreased to \$14.22 per boe in 2002 from \$16.25 per boe in 2001. The main contributors to lower earnings and cash flow were lower commodity prices and higher depletion.

	Annualized Q4 2002	2002	2001	2000
Net earnings (\$ thousands)	11,100	3,444	5,655	5,870

Earnings Ratios

As a result of strengthening commodity prices and reduced depletion charges, Progress has shown improving earnings ratios. Return on shareholders’ equity for 2003 may exceed this target if current commodity prices (in effect at the time of this writing) are sustainable. Progress targets a return on shareholders’ equity of 15 to 20 percent.

	Annualized Q4 2002	2002
Return on capital employed (%) ⁽¹⁾	10.4	4.4
Return on net investment (%) ⁽²⁾	8.3	3.6
Return on shareholders’ equity (%) ⁽³⁾	14.6	5.3

(1) Net earning plus after-tax financing charges on debt divided by average of opening and closing capital employed. Capital employed is a total of equity and long term debt.

(2) Net earnings plus after-tax financing charges on long term debt divided by average net investment. Net investment is total assets less current liabilities. Return on net investment is calculated using the average opening and closing net investment.

(3) Net earning are divided by average shareholders’ equity.

Net Earnings per BOE

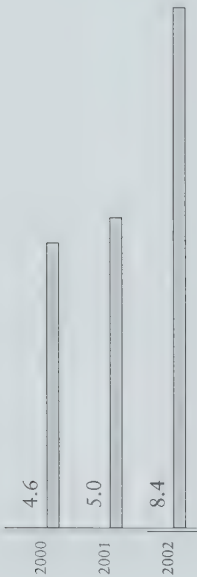
(\$/boe)	Q4 2002	2002	2001	2000
Oil, liquids and natural gas revenues	33.16	27.13	30.12	35.84
Commodity contract amortization ⁽¹⁾	(0.34)	(0.26)	-	-
Unrealized loss on financial instrument	0.56	0.22	-	-
Royalties	(7.53)	(5.34)	(5.61)	(8.30)
Operating expenses	(5.18)	(4.88)	(4.61)	(5.05)
Net operating income	20.67	16.87	19.90	22.49
General and administrative	(1.79)	(1.64)	(0.95)	(0.80)
Interest expense	(0.81)	(0.87)	(1.14)	(1.15)
Current income taxes	0.65	0.25	(1.12)	(2.21)
Capital taxes	(0.34)	(0.39)	(0.44)	(0.65)
Cash flow from operations	18.38	14.22	16.25	17.68
Commodity contract amortization	0.34	0.26	-	-
Unrealized loss on financial instrument ⁽²⁾	(0.56)	(0.22)	-	-
Depletion and depreciation	(9.36)	(9.97)	(9.05)	(7.16)
Future taxes	(4.55)	(2.25)	(2.07)	(3.42)
Net earnings	4.25	2.04	5.13	7.10

(1) The commodity contract amortization relates to the assumption of a physical sales contract acquired in conjunction with the *Campion* acquisition see Note 8 in the Consolidated Financial Statements for further details.

(2) The unrealized loss on call options relates to the mark to market value of outstanding call options at December 31, 2002 see Note 8 in the Consolidated Financial Statements for further details.



PROVEN PLUS
PROBABLE RESERVES
PER 100 SHARES
(mboe)



PRODUCTION
PER 100 SHARES
(mboe)

COMMON SHARE INFORMATION

(thousands)	2002	2001	2000
<i>Outstanding shares</i>			
Weighted average outstanding shares			
Basic	25,880	18,203	19,317
Diluted (treasury stock method)	27,459	18,980	20,570
Outstanding shares December 31 ⁽¹⁾			
Common	30,912	22,087	15,029
Class B	-	-	1,170
Basic	30,912	22,087	18,047
Diluted ⁽³⁾	34,984	25,407	19,404
(\$ thousands except per share amounts)			
<i>Per share information</i>			
Net earnings	3,444	5,655	5,870
Net earnings per share			
Basic	0.13	0.31	0.30
Diluted (treasury stock method)	0.13	0.30	0.29
Cash flow from operations	24,020	17,916	14,604
Cash flow from operations per share			
Basic	0.93	0.98	0.76
Diluted (treasury stock method)	0.87	0.94	0.71
Total assets	186,963	81,935	65,325
Total assets per share ⁽²⁾			
Basic	6.05	3.71	3.62
Diluted ⁽³⁾	5.34	3.22	3.37
Book value (shareholders' equity)	89,553	40,964	23,800
Book value per share ⁽²⁾			
Basic	2.90	1.85	1.32
Diluted ⁽³⁾	2.56	1.61	1.23
Proven plus probable reserves (mboe)	22,490	9,365	10,162
Mboe reserves per 100 shares ⁽²⁾			
Basic	72.8	42.4	56.3
Diluted ⁽³⁾	64.3	36.9	52.4
	Annualized Q4 Production	Average 2002 Production	
Production (mboe)	2,590	1,689	1,102
Production per 100 shares ⁽²⁾			
Basic	8.4	5.5	5.0
Diluted ⁽³⁾	7.4	4.8	4.3

(1) For purposes of calculating Basic and Diluted shares at year-end for 2000, the Class B shares were converted to common shares using the July 6, 2001 conversion rate of 2.58 common shares for each Class B share.

(2) Calculated using outstanding shares at year-end.

(3) Calculated using outstanding common shares, options and warrants at year-end.

Common shares issued during 2002 were:

- (1) 725,313 Common Shares on the exercise of stock options by employees. Stock options granted to employees during the year amounted to 1,550,500 shares,
- (2) 3,634,770 Common Shares on the acquisition of Campion Resources Ltd. on June 3, 2002.
- (3) 4,464,300 Common Shares at \$5.60 per share pursuant to a bought deal private placement on October 1, 2002 to fund the acquisition of the Company’s Fort St. John asset acquisition from Pengrowth.

At December 31, 2002, the Company had a total of 2,818,750 options outstanding with a weighted average exercise price of \$4.21 per share and 1,253,498 warrants outstanding with an exercise price of \$2.65 per warrant.

NET ASSET VALUE

Progress’ net asset value per share at December 31, 2002 increased by 63 percent to \$5.52 per basic share compared to \$3.39 per share in 2001 and on a diluted basis 63 percent to \$5.31 per share in 2002 compared to \$3.25 per share in 2001. The net asset value is computed using the independent engineering forward prices as presented in the pricing assumptions on page 41. The net asset value is also presented with the reserve value computed using the forward commodity price strip of March 7, 2003. Under this set of assumptions basic net asset value increased to \$7.80 per boe and \$7.33 per boe on a diluted basis.



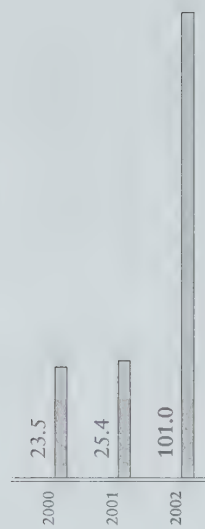
	Forward Strip ⁽³⁾	Reservoir Engineering Forward Price ⁽⁴⁾		
(\$ thousands)	2002	2002	2001	2000
Reserve value (10% discount before tax) ⁽¹⁾	253,556	182,882	82,178	97,106
Undeveloped acreage	25,000	25,000	7,500	9,912
Seismic and other assets	10,000	10,000	2,500	2,000
Working capital surplus (deficiency)	(3,933)	(3,933)	562	(5,517)
Bank debt	(43,386)	(43,386)	(17,976)	(16,409)
Basic	241,337	170,563	74,764	87,092
Exercise of stock options and warrants	15,189	15,189	7,712	2,102
Diluted	256,426	185,752	82,476	89,194
Net asset value per common share (\$)				
Basic ⁽²⁾⁽⁵⁾	7.80	5.52	3.39	4.83
Diluted ⁽²⁾⁽⁵⁾	7.33	5.31	3.25	4.60

- (1) Reserve values are for established reserves net of mark to market on outstanding financial instruments. Reserve values are based on before tax estimates of future cash flows as evaluated by our independent reserve engineers, Gilbert Lausten Jung Associates Ltd., for 2002 and 2001 and by Paddock Lindstrom and Associated Ltd. for 2000.
- (2) For the 2000 the basic and fully diluted calculation includes the common shares plus 1,170,000 Class B Shares converted to Common Shares assuming the actual conversion rate utilized upon conversion on July 6, 2001. The conversion rate was 2.58 Common Shares for each Class B Share.
- (3) The reserve value in this example is computed using the forward strip for crude oil and natural gas on March 7, 2003 which covers the years 2003 to 2008. These prices are detailed below:

	2003	2004	2005	2006	2007	2008
Light Sweet at Edmonton CDN\$/bbl	52.49	39.35	36.82	37.04	37.28	37.17
AECO CDN\$/mmbtu	8.58	6.33	5.14	4.97	5.08	5.22

For years after 2008 the prices were held constant.

- (4) The reserve values in these examples are computed using the reservoir engineering forward prices as presented on page 41 under the heading Pricing Assumptions.
- (5) Calculated using outstanding common shares, options and warrants at year-end.



CAPITAL EXPENDITURES
(\$ million)

CAPITAL RESOURCES AND INVESTMENTS

Capital Expenditures

Total capital expenditures during 2002 were \$101.0 million that included \$30.4 million in exploration and development expenditures and \$70.6 million in acquisitions. The exploration and development capital resulted in the drilling of 21 wells and the acquisition of 176,000 acres of undeveloped land. Most of the capital activity was in the second half of 2002 as the Company built and refocused its exploration and development efforts. Acquisitions during 2002 included Campion Resources Ltd. for \$40.8 million on June 3, 2002, various Fort St. John, British Columbia assets for \$27.0 million on October 4, 2002 and other minor complementary core area property acquisitions amounting to \$2.8 million during the year. The acquisitions enabled the Company to build exploration and development inventory in its two new core areas of Fort St. John, British Columbia and central Alberta.

(\$ thousands)	2002	2001	2000
Land acquisitions and retention	5,471	1,008	1,020
Geological and geophysical	2,408	1,323	1,322
Drilling and completions	15,532	11,902	12,606
Equipping and facilities	6,316	4,216	4,917
Other	636	25	77
Total exploration and development capital	30,363	18,474	19,942
Net property acquisitions	29,846	6,945	3,552
Campion Resources Ltd.	40,791	-	-
Total acquisitions	70,637	6,945	3,552
Total capital expenditures	101,000	25,419	23,494

Undeveloped Land

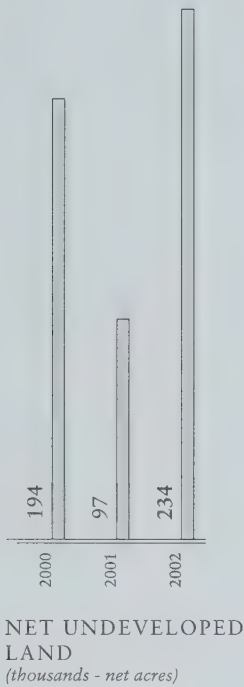
Net undeveloped land increased by 141 percent to 234,898 net acres and option lands increased to 87,650 acres during 2002 as a result of initiatives during the year, including;

Undeveloped Land

- The acquisition of Campion Resources Ltd. which added 63,000 net acres of undeveloped land,
- The acquisition of the Fort St. John area assets which contributed 30,500 net acres of undeveloped land and gave the Company access to the complementary vendor-owned 30,500 net acres through a farmin arrangement,
- Complementary core area crown and freehold land acquisitions during the year added 75,000 acres of undeveloped land.

Option Land

- In addition to the farmin in Fort St. John, two other large regional farmins with royalty trusts gave the Company access to an additional 45,600 acres of undeveloped land in the west central area of Alberta. At the time of this report, all farmin deals that the Company has entered into gave the Company control of 87,650 option acres.



During 2002 approximately 34,000 net acres expired in Saskatchewan and Manitoba.

	2002		2001		2000	
(thousands acres)	Gross	Net	Gross	Net	Gross	Net
Saskatchewan	33,401	30,194	30,040	24,739	50,616	39,782
Alberta	183,217	136,076	86,415	47,635	86,416	41,621
British Columbia	120,200	65,288	7,244	1,179	8,086	1,409
Manitoba	3,340	3,340	24,895	23,812	112,320	110,960
Total owned undeveloped	340,158	234,898	148,594	97,362	257,438	193,772
Option land	87,650	87,650				
Total controlled land	427,808	322,548				

2002 Finding & Development Costs

Cost of Reserve Additions

During 2002 the capital expenditure program resulted in total proven reserve additions, after prior year reserve revisions, of 11.0 million boe and 14.8 million boe on a proven plus probable basis resulting in total capital expenditure program finding and development costs (F&D) of \$9.22 per proven boe and \$6.82 per boe on a proven plus probable basis.

Finding costs are also presented for the exploration and development program and for the acquisitions to show the efficiencies of each capital spending initiative. The exploration and development program resulted in finding and development costs of \$8.16 per boe on a proven basis and \$5.88 per boe on a proven plus probable basis while the acquisition program resulted in finding and development costs of \$9.35 per boe on a proven basis and \$7.11 per boe on a proven plus probable basis.

Finding and development costs and other program efficiency measures are presented for 2002 only. Finding and development costs for prior periods are not representative due to the recapitalization and the new management in late 2001.

(\$ thousands)	2002
Total exploration and development capital	30,363
Net acquisitions	70,637
Total capital expenditures	101,000

	Capital Expenditures	Proven		Established		Proven Plus Probable	
		Reserves Additions	F&D Costs	Reserves Additions	F&D Costs	Reserve Additions	F&D Costs
	(\$ thousands)	(mboe)	(\$/boe)	(mboe)	(\$/boe)	(mboe)	(\$/boe)
Exploration and development program	30,363	3,719	8.16	4,443	6.83	5,166	5.88
Acquisition program	70,637	7,558	9.35	8,748	8.07	9,937	7.11
Total program (before revisions of prior periods)	101,000	11,277	8.96	13,191	7.66	15,103	6.69
Total program (after revisions of prior periods)	101,000	10,950	9.22	12,883	7.84	14,815	6.82

Reserve Replacement

(\$ thousands)		2002
Production (mboe)		1,689
Net proven reserve additions (mboe)		10,950
Proven replacement ratio		6.5
Net proven plus probable reserve additions (mboe)		14,815
Proven plus probable replacement ratio		8.8

Recycle Ratio

The recycle ratio is a measure for evaluating the effectiveness of a company’s reinvestment program. The ratio measures the efficiency of turning a barrel of oil equivalent of reserves into a new barrel of oil equivalent of production. It accomplishes this by measuring the operating netback per barrel of oil equivalent to that year’s proven plus probable finding and development costs.

	2002
Operating netbacks (\$/boe)	16.87
Proven finding and development costs before revisions of prior periods (\$/boe)	8.96
Proven reinvestment efficiency ratio	1.9
Net proven plus probable finding and development costs before revisions of prior periods (\$/boe)	6.69
Proven plus probable reinvestment efficiency ratio	2.5

	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	1	0.4	13	9.3	21	10.3
Natural gas	16	12.4	6	1.4	5	2.7
Dry and abandoned	4	2.9	4	1.8	7	3.6
Total	21	15.7	23	12.5	33	16.6
Success rate (%)	81	82	83	86	79	78

CORE AREAS

During 2002 the Company was successful in building two new core growth areas, one in west central Alberta at Gilby and the other in northeast British Columbia at Fort St. John. These areas were targeted due to their multi-zone nature, all year access and good infrastructure. The Company now controls 322,000 acres of undeveloped land and has developed a significant project inventory in its two core areas to fuel its 2003 capital program. The Company’s 2003 budget contemplates the drilling of 55 to 60 wells with 40 wells designated for these two areas. Fourth quarter production from these areas amounted to 3,424 boe per day, up from zero in 2001.

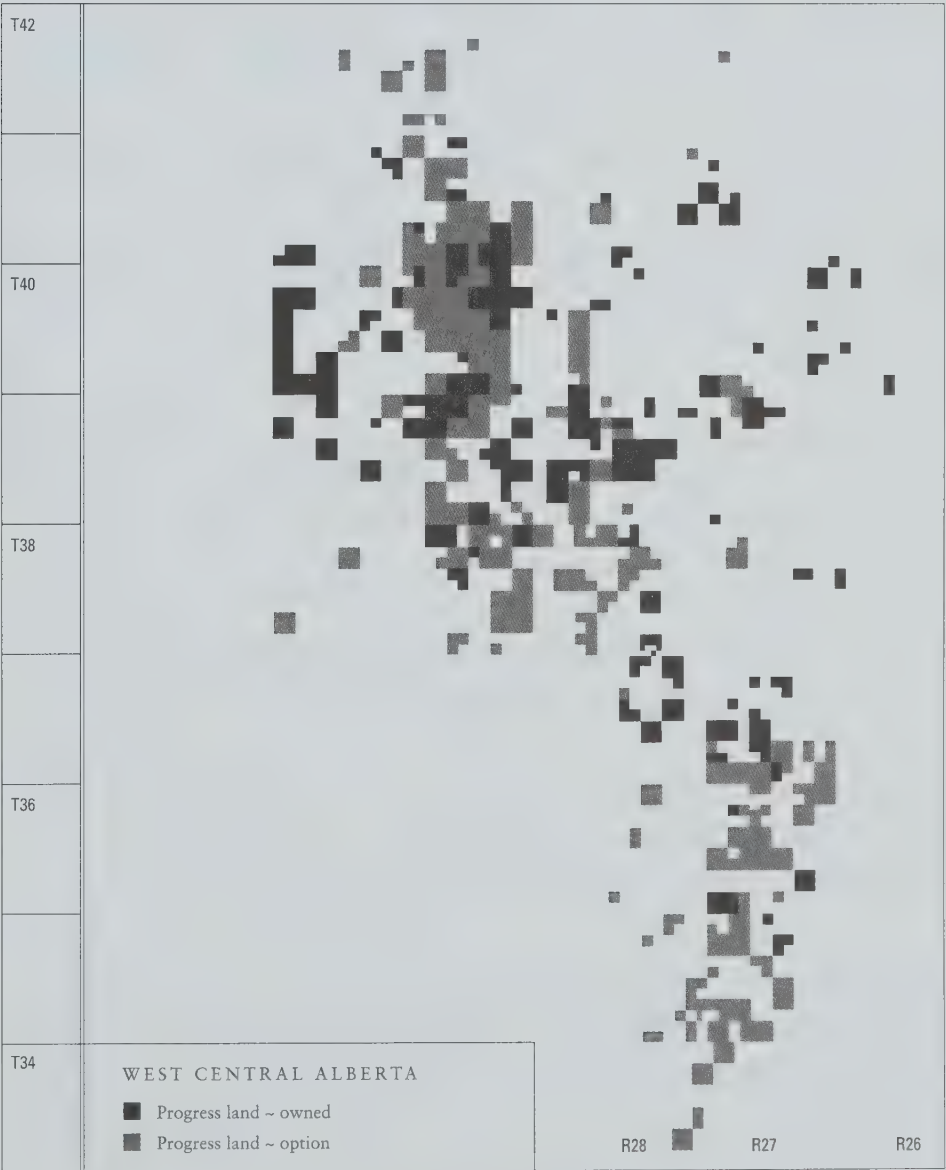
Drilling Results

The Company drilled 21 wells during 2002 consisting of eight wells in northeast British Columbia, 10 wells in Alberta and three wells in Saskatchewan.

The Company’s historic properties at Milo, Two Creek and southeast Saskatchewan/Manitoba are stable producing areas contributing cash flow to aid in the development of the newly identified core areas. During 2002 capital was incurred at Two Creek and Milo to improve the reliability of facilities. During 2003 no significant capital spending will occur in these areas other than adding compression at Milo in the first quarter.

West Central Alberta

During 2002 Progress controlled undeveloped land increased in the area from 6,880 acres to over 100,000 acres. This was accomplished with large regional farmins from area players which contributed 55,000 acres of land. In addition, Company supplemented this initial position with an active crown and freehold land acquisitions program throughout 2002. The Company’s exploration team merged six sets of 3-D seismic data covering 75 square miles and drilled eight wells resulting in seven gas wells. All of these wells are currently on production and during the fourth quarter of 2002 the area produced approximately 1,206 boe per day. The 2003 budget contemplates the drilling of over 15 wells in the area.



Fort St. John, British Columbia

During 2002 Progress controlled undeveloped land increased in the area from zero acres in the first quarter of 2002 to over 95,000 acres at December 31, 2002. This was accomplished with two large acquisitions during the year; first, the acquisition of Campion Resources Ltd. in June 2002 which contributed the initial position in the area and second, the acquisition of assets in the Fort St. John area in October 2002. As part of this second acquisition, the Company acquired a 50 percent working interest in 61,000 net acres of undeveloped land. Progress then farmed-in on the vendor's complementary 50 percent working interest in this undeveloped land and has committed to gross capital expenditures of \$10 million on the joint lands over the 18 month period beginning October 1, 2002. In addition the Company has supplemented these acquired land positions with an active crown land acquisition program and farmin activity. In late 2002 the Company's exploration team drilled five exploration wells resulting in three gas discoveries and one oil discovery. All of these wells are currently on production and during the fourth quarter of 2002 the area produced approximately 2,218 boe per day. The 2003 budget contemplates the drilling of 25 wells in the area and the shooting of three to four 3-D seismic programs.



RESERVES

Independent Reserve Evaluation

The crude oil, natural gas liquids and natural gas reserves of the Company have been reported as at January 1, 2003 by Gilbert Laustsen Jung Associates Ltd. ("GLJ") in a report dated February 4, 2003. GLJ has been engaged to conduct an independent review of the Company's reserves since 2001. Prior to 2001 Paddock Lindstrom & Associates Ltd. performed the independent review.

The properties were evaluated by GLJ on a reserve and economic forecast basis in accordance with the National Policy 2-B (Guide for Engineers and Geologists Submitting Oil and Gas Reports to Canadian Provincial Securities Administrators) definitions. The evaluators are qualified and experienced registered professional engineers and geologists and are independent of Progress. Personal field inspection of the properties was not made by GLJ as such inspections are not considered necessary in view of the information available from the files of the Company and the appropriate provincial regulatory authorities.

GLJ relies on data generally available through public sources supplemented with data provided by Progress, including but not limited to the following: land interest descriptions on a lease basis, pertinent well data (such as well logs, drill stem tests, workover details, pressure surveys, production tests), geological mapping, petrophysical studies, accounting property statements, marketing arrangements, and operating and capital budget information.

Basic well data provided by Progress for the properties were reviewed by GLJ to assist in the assignment of proven and probable reserves. GLJ has no responsibility to update its report for events and circumstances occurring subsequent to the date of that report.

Extent of Review

GLJ evaluated all of the properties of Progress and approximately 80 percent of Progress' corporate reserves and values were evaluated in full geological and engineering detail. Properties evaluated in detail included those with significant reserves and active development and properties with significant reserves and values that were identified by Progress as inactive with no development activities in 2002. The remaining properties comprising 20 percent of Progress' corporate reserves contained unitized and non-unitized reserve entities with minor reserves and values.

Summary of 2002 Reserves

At year end 2002, Progress' proven plus probable crude oil and natural gas liquids reserves increased 35 percent to 7.0 million barrels from 5.2 million barrels in 2001. Proven plus probable natural gas reserves increased 269 percent to 93.1 billion cubic feet from 25.2 billion cubic feet in 2001.

Proven producing reserves for crude oil and NGL are 94 percent (94 percent in 2001) of total proven reserves and 66 percent (72 percent in 2001) of proven plus probable reserves. Probable oil and NGL reserves account for 30 percent (23 percent in 2001) of proven plus probable oil and NGL reserves.

For natural gas, proven producing reserves are 75 percent (90 percent in 2001) of total proven reserves and 58 percent of proven plus probable reserves (77 percent in 2001). Probable natural gas reserves account for 23 percent (14 percent in 2001) of proven plus probable natural gas reserves.

Reserve Reconciliation – Oil & NGL (mbbls)

	Proven Producing	Proven Non- Producing	Total Proven	Probable	Proven Plus Probable	Proven Plus Risky Probable ⁽¹⁾
December 31, 2000	3,945	480	4,425	1,245	5,669	5,047
Extensions and discoveries	604	(46)	558	(131)	427	492
Technical revisions	(579)	(203)	(782)	(24)	(806)	(794)
Acquisitions	433	5	438	127	565	501
Dispositions	(5)	-	(5)	(2)	(7)	(6)
Reserve additions	453	(244)	209	(30)	178	193
Production	(675)	-	(675)	-	(675)	(675)
December 31, 2001	3,722	236	3,958	1,215	5,172	4,565
Extensions and discoveries	677	(144)	533	279	812	673
Technical revisions	(209)	(27)	(236)	12	(224)	(229)
Acquisitions	1,072	240	1,312	587	1,899	1,606
Dispositions	-	-	-	-	-	-
Reserve additions	1,540	69	1,609	878	2,487	2,050
Production	(696)	-	(696)	-	(696)	(696)
December 31, 2002	4,566	305	4,871	2,092	6,963	5,919

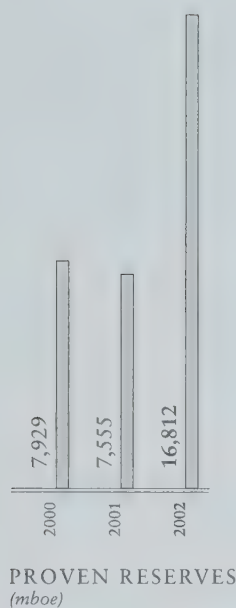
Reserve Reconciliation – Natural Gas (mmcf)

	Proven Producing	Proven Non- Producing	Total Proven	Probable	Proven Plus Probable	Proven Plus Risky Probable ⁽¹⁾
December 31, 2000	16,096	4,929	21,025	5,929	26,953	23,990
Extensions and discoveries	3,064	176	3,240	665	3,905	3,573
Technical revisions	1,528	(3,730)	(2,202)	(3,057)	(5,259)	(3,731)
Acquisitions	1,339	743	2,082	35	2,117	2,100
Dispositions	-	-	-	-	-	-
Reserve additions	5,931	(2,811)	3,120	(2,357)	763	1,942
Production	(2,565)	-	(2,565)	-	(2,565)	(2,565)
December 31, 2001	19,469	2,112	21,581	3,572	25,153	23,367
Extensions and discoveries	14,763	4,345	19,108	7,013	26,121	22,615
Technical revisions	(2,857)	2,301	(556)	163	(393)	(475)
Acquisitions	28,552	8,920	37,472	10,748	48,220	42,846
Dispositions	-	-	-	-	-	-
Reserve additions	40,458	15,566	56,024	17,294	73,948	64,986
Production	(5,960)	-	(5,960)	-	(5,960)	(5,960)
December 31, 2002	53,967	17,678	71,645	21,496	93,141	82,393

(1) The risky probable reserve have been risky by 50 percent to take into account the risk factors associated with the recovery thereof.
Numbers may not add due to rounding.



PROVEN PRODUCING
RESERVES AS
PERCENTAGE OF
TOTAL PROVEN
RESERVES
(percent)



PROVEN RESERVES
(mboe)



PROVEN PLUS
PROBABLE RESERVES
(mboe)

Reserve Reconciliation – Barrel of Oil Equivalent (mboe)

	Proven Producing	Proven Non- Producing	Total Proven	Probable	Proven Plus Probable	Proven Plus Risky Probable ⁽¹⁾
December 31, 2000	6,627	1,302	7,929	2,232	10,161	9,045
Extensions and discoveries	1,115	(19)	1,096	(20)	1,076	1,086
Technical revisions	(324)	(826)	(1,150)	(533)	(1,683)	(1,417)
Acquisitions	656	128	784	131	915	850
Dispositions	(5)	-	(5)	-	(5)	(5)
Reserve additions	1,442	(717)	725	(422)	303	514
Production	(1,103)	-	(1,103)	-	(1,103)	(1,103)
December 31, 2001	6,966	585	7,551	1,810	9,361	8,456
Extensions and discoveries	3,138	581	3,719	1,447	5,166	4,443
Technical revisions	(685)	358	(327)	39	(288)	(308)
Acquisitions	5,831	1,727	7,558	2,379	9,937	8,748
Dispositions	-	-	-	-	-	-
Reserve additions	8,284	2,666	10,950	3,865	14,815	12,883
Production	(1,689)	-	(1,689)	-	(1,689)	(1,689)
December 31, 2002	13,561	3,251	16,812	5,675	22,487	19,650

(1) The risky probable reserves have been risky by 50 percent to take into account the risk factors associated with the recovery thereof.

Numbers may not add due to rounding.

Extensions and Discoveries

A large percentage of the drilling additions were in the Gilby area in Central Alberta, capitalizing on a large farm-in that was negotiated early in 2002. Almost as significant was the development drilling in the Beg area in British Columbia, on lands obtained in the Campion acquisition. There were also numerous recompletions done in the acquired properties.

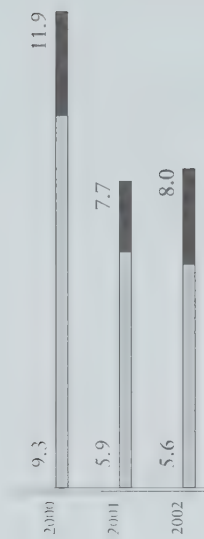
Technical Revisions

Recovery factors on some properties were slightly adjusted due to production performance. Total technical revisions were less than two percent of the remaining reserves at year end on a boe basis.

Net Acquisitions

Acquisitions during 2002 included the following:

- (1) The acquisition of Campion Resources Ltd. which contributed approximately 400 mbbls of proven crude oil and NGL reserves and approximately 22.6 bcf of proven natural gas reserves,
- (2) The acquisition of various properties from Pengrowth Corporation which contributed approximately 741 mbbls of proven crude oil and NGL reserves and approximately 13.5 bcf of proven natural gas reserves, and
- (3) Other miscellaneous complementary regional property acquisitions.



RESERVE LIFE INDEX
CRUDE OIL & NGL
(years)

□ Proven ■ Probable



RESERVE LIFE INDEX
NATURAL GAS
(years)

□ Proven ■ Probable

Reserve Life Index

The Company's reserve life index using annualized fourth quarter production is 5.6 years for proven and 8.0 years for proven plus probable crude oil and natural gas liquids reserves and 6.4 years for proven and 9.1 years for proven plus probable natural gas reserves. Reserve life was calculated using annualized fourth quarter production as this measure is more reflective of reserve life due to the level of new production added in the second half of 2002.

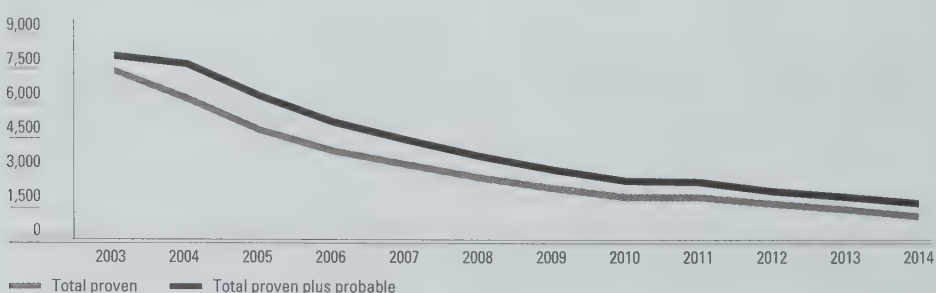
	2002	2002	2001	2000
	Using Annualized Q4 Production	Using Average Production		
<i>Crude oil & NGL</i>				
Production (mbbls)	874	696	675	477
Proven reserves (mbbls)	4,871	4,871	3,958	4,425
Proven reserve life index (years)	5.6	7.0	5.7	9.3
Proven plus probable reserves (mbbls)	6,963	6,963	5,172	5,669
Proven plus probable reserve life index (years)	8.0	10.0	7.7	11.9
<i>Natural gas</i>				
Production (mmcf)	10,295	5,959	2,565	2,093
Proven reserves (mmcf)	71,645	71,645	21,581	21,025
Proven reserve life index (years)	7.0	12.0	8.4	10.1
Proven plus probable reserves (mmcf)	93,141	93,141	25,153	26,954
Proven plus probable reserve life index (years)	9.1	15.6	9.8	12.9
<i>BOE</i>				
Production (mboe)	2,590	1,689	1,102	826
Proven reserves (mboe)	16,812	16,812	7,551	7,929
Proven reserve life index (years)	6.5	10.0	6.9	9.6
Proven plus probable reserves (mboe)	22,487	22,487	9,361	10,161
Proven plus probable reserve life index (years)	8.7	13.3	8.5	12.3

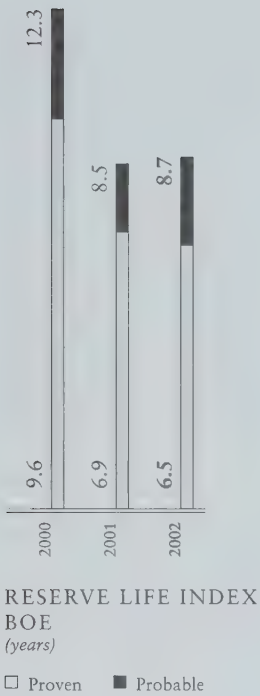
Reserve Production Profile

Presented below is the GLJ reserve production profile for the Company.

The GLJ production profile does not account for the Company's planned exploratory activities for 2002 and beyond.

Production Profile (bbls/d)





Present Value of Reserves

Revenue projections presented are based in part on forecasts prepared by GLJ of market prices, currency exchange rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future differ materially from forecasts utilized in these calculations. They do not deduct future general and administrative expenses or well and facility abandonment costs and do assume the continuance of current laws and regulations. The discounted values presented do not necessarily represent fair market value of the reserves.

(\$ millions, before income taxes)					2002				2001				2000			
Discount (%)	0	10	12	15	0	10	12	15	0	10	12	15	0	10	12	15
Proven																
Producing	216	141	133	123	103	70	66	61	116	76	71	66	116	76	71	66
Non producing	44	24	22	20	8	6	5	5	25	11	10	8	25	11	10	8
Total proven	260	165	155	143	111	76	71	66	141	87	81	74	141	87	81	74
Probable	90	43	39	33	27	13	12	11	36	21	20	18	36	21	20	18
Proven plus probable	350	208	194	176	138	89	83	76	177	108	101	92	177	108	101	92
Proven risked plus probable (1)	305	187	175	160	125	83	77	72	159	98	91	83	159	98	91	83

(1) The risked probable reserve values have been risked by 50% to take into account the risk factors associated with the recovery thereof.

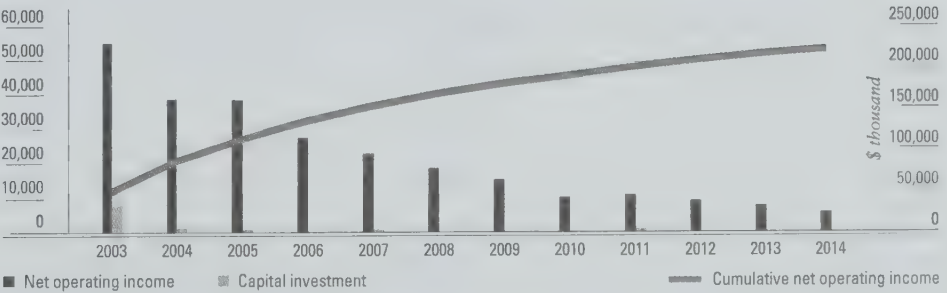
Reserve Value Reconciliation – NPV 12%

The Company’s proven plus probable reserve value at NPV 12 percent increased to \$194 million during 2002 compared to \$83 million in 2001. Below is a reconciliation of this difference in reserve value.

(\$ million before taxes)		2002
Opening reserve value - proven plus probable		83
Net present value of current year production		(24)
Net present value of current year reserve additions		123
Change in net present value due to pricing		12
Closing reserve value - proven plus probable		194



Yearly and Cumulative Net Operating Income
(\$ thousands)



* Total proven reserves, undiscounted and net of capital investment required to produce proven non producing reserves.

Net Future Capital Expenditures

The reserve report incorporates future capital expenditure requirements to bring proven non-producing and probable reserves on production as well as to maintain proven producing reserves.

Undiscounted (\$ thousands)	2002	2001	2000
Proven - producing	248	212	374
Proven - non producing	10,722	2,226	1,364
Proven	10,970	2,438	1,738
Probable	6,629	1,586	4,637
Proven plus probable	17,599	4,024	6,375

2001 Year End Reserves by Province

	Oil & NGL (mbbls)			Natural gas (bcf)		
	Proven	Probable	Proven plus probable	Proven	Probable	Proven Plus Probable
Alberta	1,545	568	2,113	9.8	2.2	12.0
British Columbia	-	-	-	11.4	1.4	12.8
Saskatchewan	1,780	402	2,182	0.4	-	0.4
Manitoba	633	244	877	-	-	-
	3,958	1,214	5,172	21.6	3.6	25.2

2002 Year End Reserves by Province

	Oil & NGL (mbbls)			Natural Gas (bcf)		
	Proven	Probable	Proven Plus Probable	Proven	Probable	Proven Plus Probable
Alberta	1,386	814	2,200	27.3	8.5	35.8
British Columbia	1,392	681	2,073	43.4	12.7	56.2
Saskatchewan	1,520	359	1,879	0.8	0.3	1.1
Manitoba	573	238	811	-	-	-
	4,871	2,092	6,963	71.6	21.5	93.1

Reserve Committee

In November 2002 the Company established a Reserve Committee of the Board of Directors. Prior to 2002 these responsibilities were delegated to the entire Board of Directors. The mandate of the Reserve Committee is detailed in the Corporate Governance section of the Company’s 2002 Information Circular.

Pricing Assumptions

The pricing forecast presented below has been prepared by Gilbert Laustsen Jung Associates Ltd. as at January 1, 2003. The pricing presented for 2000 was prepared by Paddock Lindstrom Associates Ltd. These prices have been utilized in determining the reserves and cash flow forecasts in this section.

Year	Crude Oil ⁽¹⁾ (US\$/bbl)			Crude Oil ⁽²⁾ (CDN\$/bbl)			Natural Gas ⁽³⁾ (CDN\$/mbtu)		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
1998	14.43			20.09			2.02		
1999	19.24			27.35			2.91		
2000	30.20			44.24			5.55		
2001	25.90		27.00	38.93		39.91	5.46		7.35
2002	26.08	20.00	24.00	39.61	30.75	34.80	4.08	3.95	5.36
2003	25.50	21.00	23.00	38.50	31.25	32.78	5.65	4.35	4.89
2004	22.00	21.00	23.00	32.50	30.50	32.27	5.00	4.45	4.44
2005	21.00	21.00	23.46	30.50	29.50	32.43	4.70	4.50	4.45
2006	21.00	21.25	23.93	30.50	29.50	33.08	4.85	4.50	4.54
2007	21.25	21.75	24.41	30.50	30.00	33.74	4.85	4.50	4.63
2008	21.75	22.00	24.90	31.00	30.50	34.42	4.85	4.50	4.72
2009	22.00	22.25	25.39	31.50	31.00	35.11	4.85	4.55	4.82
2010	22.25	22.50	25.90	32.00	31.50	35.81	4.90	4.60	4.91
2011	22.50	23.00	26.42	32.50	32.00	36.52	4.95	4.70	5.01
2012	23.00	23.25	26.95	33.00	32.50	37.25	5.05	4.75	5.11
Thereafter	+1.5%/yr	+2.0%/yr	+2.0%/yr	+1.5%/yr	+2.0%/yr	+2.0%/yr	+1.5%/yr	+2.0%/yr	+2.0%/yr

(1) West Texas Intermediate at Cushing, Oklahoma

(2) Light Sweet at Edmonton, Alberta

(3) AECO

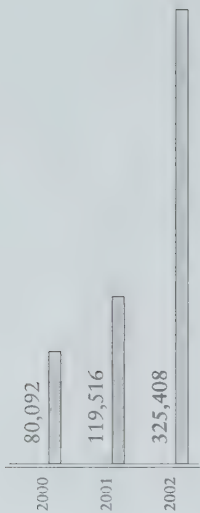
Figures represent actual prices

Additional Disclosure on Reserves

For more disclosure on the Company’s reserves see Summary of Estimated Reserves in the Annual Information Form.

CAPITALIZATION & FINANCIAL RESOURCES

The Company’s total capitalization increased 172 percent to \$325.4 million during 2002 with a market value of common shares representing 76 percent of total capitalization. Debt and working capital represented 15 percent of total capitalization, while site restoration, commodity contracts and future income taxes accounted for nine percent. The market value of the Company’s common shares increased to \$247.3 million as a result of increased outstanding shares and an increase in the Company’s share price.



TOTAL CAPITALIZATION (\$ thousands)



DEBT TO TRAILING CASH FLOW (times)

Total Market Capitalization

(\$ thousand except per share amounts)	2002	%	2001	%	2000	%
Common shares outstanding (thousands)	30,912		22,087		15,029	
Share price ⁽¹⁾	8.00		3.95		2.75	
Market value of common shares	247,296	76	87,245	73	41,330	52
Class B shares outstanding (thousands)	-		-		1,170	
Share price	-		-		4.80	
Market value of class B shares ⁽²⁾	-		-		5,616	7
Total market capitalization	247,296	76	87,245	73	46,946	59
Working capital deficiency (surplus)	3,933		562		5,517	
Bank debt	43,386		17,976		16,409	
Total debt	47,319	15	17,414	15	21,926	27
Site restoration and reclamation	2,574	1	1,682	1	847	1
Commodity contracts	3,694	1	-		-	
Future incomes taxes	24,525	7	13,175	11	10,373	13
Total capitalization	325,408	100	119,516	100	80,092	100
Total debt to total capitalization (%)	15		15		27	

(1) For 2002 represents the last price the Common Shares traded on the TSX. For 2001 represents the last price the Common Shares traded on the CDNX.

(2) Represents the last price the Class B shares traded on the CDNX. During 2001 the Class B shares were converted to Common shares.

At December 31, 2002 the Company had outstanding on its credit facility approximately \$43.4 million and had a working capital deficit of \$3.9 million, resulting in \$47.3 million of total debt. This total debt level represents approximately 2.0 times 2002 cash flow from operations and approximately 1.1 times budgeted 2003 cash flow from operations. The Company has a \$62 million credit facility and is well positioned to execute its plans for 2003.

Key Debt Ratios

(\$ thousands)	2002	2001	2000
Working capital deficiency (surplus)	3,933	(562)	5,517
Bank debt	43,386	17,976	16,409
Total debt	47,319	17,414	21,926
Debt to cash flow ratio			
Cash flow from operations	24,020	17,916	14,604
Total debt	47,319	17,414	21,926
Years cash flow to repay total debt			
Trailing cash flow	1.97	0.97	1.50
Forward cash flow	1.09	0.73	1.22
Asset coverage ratio			
Total assets	186,963	81,935	65,325
Total debt	47,319	17,414	21,926
Asset coverage	3.95	4.71	2.98
Total debt/equity ratio			
Total debt	47,319	17,414	21,926
Shareholders' equity	89,553	40,964	23,800
Total debt/equity	0.53	0.43	0.92

EMERGING ACCOUNTING ISSUES

The Accounting Standards Board has issued a new accounting guideline regarding the disclosure of guarantees which will be effective starting January 1, 2003. This guideline requires companies to provide additional disclosure regarding certain guarantee contracts that may require payments contingent on specified types of future events. The Company is currently assessing these requirements to determine whether it has any such guarantee contracts.

The Accounting Standards Board issued a new accounting guideline regarding hedging relationships effective January 1, 2004. The guideline specifies certain criteria that must be met for an item to be accounted for as a hedge. The criteria includes ensuring the hedge meets the risk management objective and strategy, the instrument must be designated as a hedge and the hedge must be effective. The Company will be assessing these requirements to ensure it complies with the guideline by January 1, 2004.

OUTLOOK AND PROSPECTS FOR FUTURE GROWTH

Progress remains confident of its ability for success and future growth. The Company believes it can deliver base production growth averaging 8,000 boe per day in 2003 from its internal exploration and development program inventory. This growth will be derived from the \$50 million budgeted capital program approved by the Board of Directors. The 2003 program will be invested to develop existing internal opportunities, test some new exploratory prospects, build an inventory of exploitation opportunities and fund opportunities that will fuel growth in 2004.

The Company plans on capital expenditures beyond the budgeted levels focused on:

- Consolidating and on-trend acquisitions
- Opportunity driven core area acquisitions
- Significant exploratory partnerships that would be regionally complementary to the Company's focused areas.

These expenditures are opportunity driven and will occur only if the Company is able to identify and execute on transactions that it deems to be economic and strategic. Financing of these opportunities could involve the sale of non-core properties.

2003 Capital Budget

During 2002 Progress has been successful in the creation of two new high quality growth areas at Fort St. John, British Columbia and West Central Alberta. The Company has assembled approximately 235,000 net acres of undeveloped land and almost 88,000 acres of option land and has established a strong exploration momentum with its 2002 drilling results and enters 2003 with a large and balanced inventory of drillable prospects split between light oil and natural gas.

The Company is forecasting average 2003 production of approximately 8,000 boe per day with an exit production rate for 2003 of approximately 9,000 boe per day. Cash flow is forecast to be approximately \$43 million for 2003. The Company's 2003 commodity price assumptions are for WTI crude oil prices of US\$23.00 per barrel, resulting in a Progress realized wellhead price of approximately CDN\$29.00 per barrel and NYMEX natural gas prices of US\$3.70 per mmbtu resulting in a realized Progress wellhead price of CDN\$4.50 per mcf.

2003 Sensitivities

Based on the above assumptions, the following sensitivities are provided to demonstrate the impact on cash flow and earnings of changes in commodity prices, the Canadian currency and interest rates.

(\$ thousands)	Cash flow From Operations	Earnings
Impact on 2003:		
Change in West Texas Intermediate oil price by US\$1.00 per barrel	880	580
Change in average field price of natural gas by CDN\$0.10 per mcf	970	640
Change in value of CDN dollar compared to US dollar by CDN\$0.01	200	140
Change of 1% in prime interest rates	500	340

* Sensitivity calculations are based on the 2003 budget and assume a US dollar exchange rate of \$1.4749.

The Company's 2003 capital program is forecast to be \$50 million with \$11 million for land and seismic, \$28 million for drilling and \$11 million for facilities. The program will result in the drilling of approximately 50 wells. The net debt at December 31, 2002 was approximately \$47 million and is forecasted to be approximately \$54 million at December 31, 2003.

RISK ASSESSMENT

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following reviews the general and specific risks and includes Progress' approach to managing these risks.

Commodity Risks

Finding

Oil and gas exploration requires manpower and capital to generate and test exploration concepts. The eventual testing of a concept will not necessarily result in the discovery of economical reserves. Progress attempts to minimize finding risk by ensuring that:

- The majority of prospects have multi-zone potential.
- Activity is focused in core regions where expertise and experience is greatest.
- Number of wells drilled is large enough to increase the probability of statistical success rates.
- Working interests are targeted at over 60 percent in new prospects.
- Geophysical techniques are utilized where appropriate.

Investment Risk Profile

The Company's investment selection process is based on risk analysis to ensure capital expenditures balance the objectives of immediate cash flow growth (development activity) and future cash flow from the discovery of reserves (exploration). This careful prospect selection process can yield consistent and efficient results. The Company focuses its activity in two core areas and four major play types, allowing it to leverage its experience and knowledge in these areas further aiding efficiencies. The Company attempts to maintain a broad range of investment choices to limit the investment risk by continually investing a portion of its annual budget for future years' activity. The Company attempts to use farm-outs to minimize risk on plays it considers higher risk.

Production

Beyond exploration risk, there is the potential that the Company's oil and natural gas reserves may not be economically produced at prevailing prices. Progress minimizes this risk by generating exploration prospects internally, targeting high quality products and attempting to operate the associated project. Operational control allows the Company to control costs, timing, method and sales of production. Production risk is also minimized by concentrating exploration efforts in regions where facilities and infrastructure are Progress-owned, or the Company can control the future development of new facilities and infrastructure.

Reserve Estimates

Estimates of economically recoverable oil and natural gas reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

The Company's independent engineering firm, Gilbert Laustsen Jung Associates Ltd. ("GLJ"), uses a deterministic approach in the estimation of reserves. Reserves are assessed using a discrete value for each parameter in the calculation of reserves, such that the resultant reserve value is consistent with the certainty level associated with the reserve classification. Where deemed appropriate, risk modeling is utilized to determine reserve probability distributions. Regardless of which method is employed, the following definitions are followed by GLJ in their analysis:

- **Proven Reserves** – Those reserves estimated as recoverable under current technology and existing economic conditions in the case of constant price and cost analyses and anticipated economic conditions in the case of escalated price and cost analyses, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

- Probable Reserves – Those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved, but where such analysis suggests the likelihood of their existence and future recovery under current technology and existing or anticipated economic conditions. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

Financial and Liquidity Risks

Progress relies on various sources of funding to support its growing capital expenditure program:

- Internally generated cash flow provides the minimum level of funding on which the Company's annual capital expenditures program is based.
- Debt may be utilized to expand capital programs when it is deemed appropriate.
- New equity, if available and if on favorable terms, may be utilized to expand exploration programs.

Cash flow is influenced by factors, which the Company cannot control, such as commodity prices, the US/CDN exchange rate, interest rates and changes to existing government regulations and tax policies. Should circumstances affect cash flow in a detrimental way, Progress would respond by increasing debt to within the Company's self-imposed debt guideline or reducing capital expenditures.

Environmental and Safety Risks

There are potential risks to the environment inherent in the business activities of the Company. The Board of Directors has reviewed and approved policies and procedures covering environmental risks, emergency response and employee safety. These policies and procedures are designed to protect and maintain the environment with respect to all corporate operations on behalf of shareholders, employees and the public at large. The Company mitigates environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations and maintaining adequate insurance.

The Company has estimated future site restoration and abandonment costs will total \$14.4 million and has recognized \$1.3 million through increased depletion in 2002. The Company reviews its site restoration and abandonment obligations annually and adjusts its provision based on current costs.

Inflation Risks

Inflation risks subject the Company to potential erosion of product netbacks. For example, increasing domestic prices for oil and natural gas production equipment and services can inflate the costs of operations.

Supply of Service and Production Equipment

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce these reserves in an economic and timely fashion. In periods of increased activity these services and supplies can become difficult to obtain. The Company attempts to mitigate this risk by developing strong long term relationships with suppliers and contractors and maintains an appropriate inventory of production equipment.

Risk Management

The objectives of Progress' Risk Management Policy is to secure the capital program and cover debt payments by ensuring that budgeted cash flow levels are attained through the minimization of exposure to commodity price, foreign exchange and interest rate volatility. The objectives are achieved through the use of financial instruments or by through fixed price contracts for the delivery of physical volumes. The program is subject to certain targets and guidelines as approved by the Board of Directors from time to time. Effective controls and procedures are in place to ensure that the mandate is followed.

Marketing Risks

Demand for crude oil and natural gas produced by the Company exists within Canada and the US, however, crude oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Demand for natural gas liquids is dictated predominantly by demand for petrochemicals in North American and off-shore markets. Progress mitigates the risks as follows:

- Crude oil production is of a high quality and hence not subject to adverse quality differentials.
- Natural gas is connected to mature pipeline infrastructure that operates with minimal interruptions.
- Exploration efforts target high quality oil and liquid rich natural gas reserves.
- Exploration efforts are concentrated in core regions where marketing expertise levels are highest. Marketing synergies can be achieved with the existing production base.
- Sale arrangements vary in term and pricing structure to develop a portfolio to minimize risk of exposure to any one market.
- Financial instruments are used where appropriate to manage commodity price volatility.

Technology Risks

The Company relies on information technology to manage its day to day operations and perform reporting obligations including the preparation of financial statements, reporting to joint partners and various governments in relation to payment of royalties and taxes.

**MANAGEMENT'S
REPORT**

The accompanying consolidated financial statements of Progress Energy Ltd. and all the information in this annual report are the responsibility of management and have been approved by the Board of Directors.

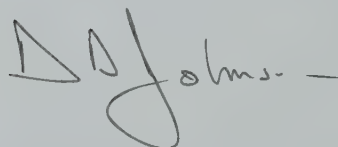
The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Progress Energy Ltd. maintains appropriate systems of internal accounting and administrative controls of high quality. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded.

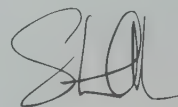
The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee of the Board of Directors, composed entirely of independent directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy and financial reporting matters. The Committee reviews the financial statements and Management's Discussion and Analysis and recommends their approval to the Board of Directors. The Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of the external auditors.

The financial statements have been audited by KPMG LLP, the external auditors, in accordance with Canadian generally accepted auditing standards on behalf of the shareholders. KPMG LLP have full and free access to the Audit Committee.



David D. Johnson
President and CEO



Steven A. Allaire
Vice President Finance and CFO

Calgary, Canada
February 25, 2003

**AUDITORS'
REPORT****To the Shareholders of Progress Energy Ltd.**

We have audited the consolidated balance sheets of Progress Energy Ltd. as at December 31, 2002 and 2001 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatements. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

A handwritten signature in black ink that reads "KPMG LLP". The letters are stylized and slanted to the right.

Chartered Accountants
Calgary, Canada
February 25, 2003

CONSOLIDATED
BALANCE SHEETS

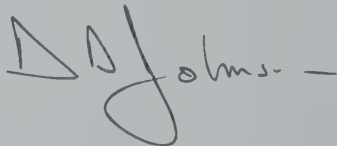
<i>As at December 31 (\$ thousands)</i>	2002	2001
ASSETS		
Current		
Cash and short-term investments	2,946	-
Accounts receivable	13,519	8,009
Prepaid expense and deposits	2,833	691
	19,298	8,700
Property, plant and equipment (Note 3)	158,665	73,235
Goodwill (Note 2)	9,000	-
	186,963	81,935
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	23,231	8,138
	23,231	8,138
Bank debt (Note 4)	43,386	17,976
Commodity sales contract (Note 8)	3,694	-
Site restoration and abandonment	2,574	1,682
Future income taxes (Note 6)	24,525	13,175
	97,410	40,971
SHAREHOLDERS' EQUITY		
Share capital and warrants (Note 5)	74,753	29,608
Retained earnings	14,800	11,356
	89,553	40,964
	186,963	81,935

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board:



Director



Director

**CONSOLIDATED
STATEMENTS OF
EARNINGS AND
RETAINED
EARNINGS**

<i>Year ended December 31 (\$ thousands except per share amounts)</i>	2002	2001	2000
REVENUES			
Petroleum and natural gas	45,820	33,202	29,593
Royalties (net of Alberta Royalty Tax Credit)	(9,023)	(6,183)	(6,851)
	36,797	27,019	22,742
EXPENSES			
Operating	8,246	5,084	4,170
General and administrative	2,765	1,046	664
Financing charges	1,470	1,253	946
Depletion and depreciation	16,833	9,975	5,913
	29,314	17,358	11,693
Earnings before taxes	7,483	9,661	11,049
TAXES (Note 6)			
Capital taxes	658	482	534
Current income taxes (recovery)	(422)	1,238	1,824
Future income taxes	3,803	2,286	2,821
	4,039	4,006	5,179
Net earnings	3,444	5,655	5,870
Retaining earnings, beginning of year	11,356	6,644	1,399
Redemption of shares (Note 5)	-	(943)	(625)
Retained earnings, end of year	14,800	11,356	6,644
Net earnings per share (Note 5)			
Basic	0.13	0.31	0.30
Diluted	0.13	0.30	0.29

See accompanying notes to the consolidated financial statements

**CONSOLIDATED
STATEMENTS OF
CASH FLOWS**

<i>Year ended December 31 (\$ thousands except per share amounts)</i>	2002	2001	2000
Cash provided by (used in):			
OPERATIONS			
Net earnings	3,444	5,655	5,870
Depletion and depreciation	16,833	9,975	5,913
Amortization of commodity sales contract	(433)	-	-
Unrealized loss on financial instrument <i>(Note 8)</i>	373	-	-
Future income taxes	3,803	2,286	2,821
Cash flow from operations	24,020	17,916	14,604
Changes in non-cash working capital <i>(Note 7)</i>	3,363	(6,147)	2,634
	27,383	11,769	17,238
FINANCING			
Increase in bank debt	12,130	1,567	6,991
Issue of shares	26,034	14,385	302
Share issue costs	(1,420)	(635)	-
Redemption of shares	-	(1,725)	(969)
	36,744	13,592	6,324
INVESTING			
Corporate acquisition <i>(Note 2)</i>	(599)	-	-
Capital asset additions	(60,210)	(25,419)	(23,494)
Site restoration and abandonment expenditures	(372)	(10)	-
	(61,181)	(25,429)	(23,494)
Increase (decrease) in cash and short-term investments	2,946	(68)	68
Cash and short-term investments, beginning of year	-	68	-
Cash and short-term investments, end of year	2,946	-	68
Cash flow from operations per share <i>(Note 5)</i>			
Basic	0.93	0.98	0.76
Diluted	0.87	0.94	0.71

See accompanying notes to the consolidated financial statements

**1.
SIGNIFICANT
ACCOUNTING
POLICIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS****Nature of Business and Basis of Presentation**

Progress Energy Ltd. (the “Company”) is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta, Saskatchewan and Manitoba. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that effect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries and partnership.

Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Company only reflects its proportionate interest in such activities.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the provision for future site restoration and abandonment costs are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

Cash and Short-Term Investments

Cash and short-term investments consist of cash in the bank, less outstanding cheques and short-term deposits with a maturity of less than three months.

Petroleum and Natural Gas Properties

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

The Company conducts a cost recovery ceiling test to ensure capitalized costs less accumulated depletion and depreciation, future income taxes and the accumulated provision for future site restoration costs do not exceed the estimated future net revenues plus the cost of unproved properties, net of impairments. The future net revenues are calculated based on proven reserves, using year-end prices and costs. Estimated future capital costs, recurring general and administrative expenses, future financing costs, future site restoration costs, and income taxes are deducted in determining future net revenues. Any amount carried on the balance sheet in excess of the ceiling test limit is charged to current operations as additional depletion.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion and Depreciation

Capitalized costs, together with estimated future capital costs associated with proven reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proven reserves of petroleum and natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion calculation.

Other assets, which is comprised of office equipment and furniture and fixtures, are recorded at cost and are depreciated over their useful life on a declining balance basis at 20 percent.

Site Restoration and Abandonment

A provision for future site restoration and abandonment costs, including the removal of production facilities at the end of their useful lives, and net of salvage values, is calculated using the unit of production method. Costs are estimated each year by management based upon current regulations and industry practices. The annual charge is recorded as additional depletion and depreciation. Actual costs incurred are charged against the accumulated liability.

Goodwill

Goodwill is tested for impairment on an annual basis in the fourth quarter. If indications of impairment are present, a loss would be charged to earnings for the amount that the carrying value of goodwill exceeds its fair value.

Derivative Financial Instruments

The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Company does not enter into derivative financial instruments for trading or speculative purposes.

The derivative financial instruments are initiated within the guidelines of the Company's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Company's firm commitment or forecasted transaction and the underlying basis of the instrument, such as commodity price or foreign exchange rate, matches the Company's exposure.

The Company enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to petroleum and natural gas revenue over the term of the contract.

The Company may enter into foreign exchange forward contracts to hedge anticipated US dollar denominated petroleum and natural gas sales. These derivatives, accounted for as hedges, are not recognized on the balance sheet. The gains and losses on these derivatives are recognized as an adjustment to petroleum and natural gas revenues when the sale is recorded.

Gains and losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings when those changes occur. In some circumstances, the Company will sell call options in order to recover the premium paid on the purchase of put options for the same or similar periods. These written call options are only accounted for as a component of the hedging instrument if all of the critical terms are the same and no net premium is received. Gains or losses from changes in the fair value of these written call options that do not qualify for hedge accounting, are recognized as an adjustment to petroleum and natural gas revenue as they occur.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

Income Taxes

The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Flow-Through Shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and share capital are adjusted by the estimated cost of the renounced tax deduction when the shares are issued.

Stock Based Compensation Plan

The Company accounts for its stock based compensation plan using the intrinsic-value method. Under this method, no expense is recognized in the financial statements for share options granted to employees or directors when the options are issued at market value. Consideration paid by directors, officers and employees on the exercise of stock options under the stock option plan is recorded as share capital.

Per Share Information

Per share information is calculated on the basis of the weighted average number of common shares outstanding during the fiscal year. Diluted per share information reflects the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options would be used to buy back common shares at the average market price for the period.

**2.
CAMPION
RESOURCES LTD.
ACQUISITION**

Effective June 3, 2002, the Company acquired all of the issued and outstanding common shares of Campion Resources Ltd. (“Campion”), a public company, involved in the exploration, development and production of natural gas in central Alberta and northeast British Columbia. The consideration offered was 0.40 of a Progress common share for each Campion common share resulting in 3,634,770 Progress shares being issued. The value of the transaction, based on a closing price of Progress of \$5.48 on April 12, 2002, was \$20.5 million (including \$0.6 million in transaction costs) plus the assumption of Campion’s debt. The transaction was accounted for using the purchase method. The purchase price resulted in an excess purchase price over the fair value of assets acquired of approximately \$9.0 million which has been reflected as goodwill. The acquisition of Campion provided Progress with an immediate undeveloped land and operating position in two core areas, central Alberta and northeast British Columbia where Progress is building area dominance that will facilitate efficient growth. The accounts include the results of Campion effective June 3, 2002.

The purchase price equation is as follows:

(\$ thousands)	
Cost of acquisition:	
Shares issued	19,919
Transaction costs	599
Total	20,518
Allocated:	
Accounts receivable and other	2,472
Property, plant and equipment	40,791
Goodwill	9,000
Accounts payable and accrued liabilities	(6,178)
Long-term debt	(13,280)
Commodity sales contracts (Note 8)	(4,127)
Future income taxes	(8,160)
	20,518

3.
PROPERTY, PLANT
AND EQUIPMENT

(\$ thousands)	2002	2001
Petroleum and natural gas properties	192,534	92,170
Other assets	1,041	406
	193,575	92,576
Accumulated depletion and depreciation	(34,910)	(19,341)
Net book value	158,665	73,235

During the year ended December 31, 2002, the Company capitalized \$0.7 million (2001 - \$0.7 million,) of general and administrative expenses related to exploration and development activities. As at December 31, 2002, the depletion calculation excluded unproved properties of \$23.0 million (2001 - \$4.7 million). As at December 31, 2002, the estimated future site restoration costs to be accrued over the life of the remaining proved reserves are \$11.8 million (2001 - \$6.7 million).

4.
BANK DEBT

(\$ thousands)	2002	2001
Direct advances	-	514
Bankers' acceptances	43,386	17,462
Total bank debt	43,386	17,976

The Company has a revolving term credit facility available up to \$62 million with a Canadian bank. The facility is available on a revolving basis for a period of 364 days until May 31, 2003. On this date, at the Company's discretion, the facility is available on a non-revolving basis for a one year term until May 31, 2004, at which time the facility would be due and payable. Alternatively the facility may be extended for a further 364 day period at the request of the Company and subject to approval by the bank. The credit facility is secured by a \$150 million fixed and floating charge debenture on the assets of the Company. The \$62 million borrowing base is subject to a semi-annual and annual review by the bank. The next annual review of the borrowing base is scheduled for March 31, 2003.

Borrowing is available by way of direct advances or bankers' acceptances and the facility provides for various interest rates and banker acceptance fee options, which are based on market rates in effect at the time.

5.
SHARE CAPITAL

Authorized
Unlimited number of voting Common Shares, without par value.
Unlimited number of voting Class B Shares

Issued		
(\$ thousands except share amounts)		
	Number	Amount
COMMON SHARES		
Balance at December 31, 1999	14,922,000	10,727
Issued on exercise of stock options	485,000	257
For cash, pursuant to flow-through private placement	12,500	35
Tax effect on flow-through shares renounced	-	(16)
For cash, pursuant to private placement	4,000	10
Redemption of shares	(394,800)	(340)
Balance at December 31, 2000	15,028,700	10,673
Issued on conversion of Class B shares	3,018,600	6,483
Issued on exercise of stock options	397,500	535
For cash, pursuant to flow-through private placement	700,000	1,701
Tax effect on flow-through shares renounced	-	(788)
For cash, pursuant to private placement	3,553,498	11,873
Share issue expense, net of tax effect of \$271	-	(364)
Redemption of shares	(610,900)	(781)
Balance at December 31, 2001	22,087,398	29,332
Issued on exercise of stock options	725,313	1,034
Shares issued on the acquisition of Campion (Note 2)	3,634,770	19,919
For cash, pursuant to private placement	4,464,300	25,000
Share issue expense, net of tax effect of \$613	-	(808)
Balance at December 31, 2002	30,911,781	74,477
CLASS B SHARES		
Balance at December 31, 1999	1,170,900	6,487
Redemption of shares	(900)	(4)
Balance at December 31, 2000	1,170,000	6,483
Conversion to Common Shares	(1,170,000)	(6,483)
Balance at December 31, 2001 and 2002	-	-
WARRANTS		
Balance at December 31, 2000	-	-
Issued pursuant to flow-through private placement	700,000	154
Issued pursuant to private placement	553,498	122
Balance December 31, 2001 and 2002	1,253,498	276
Total share capital and warrants	-	74,753

Conversion of Class B Shares to Common Shares

On July 6, 2001, the Company exercised its option to convert the issued and outstanding Class B Shares. As a result of the conversion, 2.58 Common Shares were issued for each issued and outstanding Class B Share. The conversion resulted in the issuance of 3,018,600 Common Shares for all the issued and outstanding Class B Shares of the Company.

Issue of Shares and Warrants

On November 20, 2001 the Company issued, on a private placement basis to certain officers of the Company, 553,498 units, with each unit consisting of one Common Share and one Warrant, for \$2.43 per unit and 700,000 units, with each unit consisting of one flow-through Common Share and one Warrant, for \$2.65 per unit. Total consideration for all 1,253,498 units was \$3.2 million which included a value of \$0.22 per Warrant for a total of \$0.3 million. One Common Share may be issued for each Warrant at a price of \$2.65 per share. The Warrants are exercisable effective November 5, 2002 and expire November 5, 2004. No warrants have been exercised as at December 31, 2002.

Normal Course Issuer Bid

During 2001, the Company purchased and cancelled 610,900 Common Shares (2000 - 394,800 Common Shares and 900 Class B Shares) for a total consideration of \$1.7 million (2000 - \$1.0 million) pursuant to the normal course issuer bids (the "Bid") approved by the Canadian Venture Exchange. Of these totals, 119,400 Common Shares (2000 - 394,800 Common Shares and 900 Class B Shares) were purchased and cancelled for a total consideration of \$0.3 million (2000 - \$1.0 million) under a Bid that expired on March 29, 2001 and 491,500 Common Shares were purchased and cancelled for a total consideration of \$1.4 million under a Bid that expired July 17, 2002. Of the total consideration paid, \$0.8 million (2000 - \$0.3 million), being the adjusted cost base of the shares for the Company, was charged to share capital and the balance of \$0.9 million (2000 - \$0.6 million) was charged to retained earnings. Under the Bid that expired July 17, 2002, the Company could have purchased up to 896,395 Common Shares.

Flow-Through Share Expenditures

Pursuant to the November 20, 2001 flow-through share offering, the Company renounced \$1.8 million of qualifying expenditures effective December 31, 2001. Of the total qualifying expenditures renounced, all costs were incurred in 2002.

Stock Options

Under the terms of the stock option plan (the "Plan"), directors, officers and employees are eligible to be granted options to purchase Common Shares. The Plan provides for the granting of up to 10 percent of the issued and outstanding Common Shares of the Company. As at December 31, 2002, the Company could grant up to 3,091,178 options. Options granted under the Plan have a term of five years to expiry and vest equally over a three year period starting on the first anniversary date of the grant. The

exercise price of each option equals the market price of the Company’s Common Shares on the date of grant. At December 31, 2002, 2,818,750 options with exercise prices between \$1.87 and \$6.82 were outstanding and exercisable at various dates to the year 2007.

The following table sets forth a reconciliation of the Plan activity through December 31, 2002:

<i>(\$ except share amounts)</i>	Number of Options	Weighted Average Exercise Price	Number Exercisable at Year-end	Weighted Average Exercise Price
Balance, December 31, 1999	1,346,250	0.95	701,250	0.59
Granted	605,000	2.23		
Exercised	(485,000)	0.53		
Cancelled	(110,000)	2.40		
Balance, December 31, 2000	1,356,250	1.55	471,563	1.06
Granted	1,107,750	2.55		
Exercised	(397,500)	1.35		
Balance, December 31, 2001	2,066,500	2.12	776,250	1.57
Granted	1,550,500	5.71		
Exercised	(725,313)	1.43		
Cancelled	(72,937)	4.89		
Balance, December 31, 2002	2,818,750	4.21	474,938	2.47

The following table sets forth additional information related to stock options outstanding at December 31, 2002:

Range of Exercise Price <i>(\$/share)</i>	Options Outstanding			Exercisable Options	
	Number of Options	Weighted Average Exercise Price <i>(\$/share)</i>	Weighted Average Years to Expiry	Number of Options	Weighted Average Exercise Price <i>(\$/share)</i>
1.87 - 2.80	1,152,500	2.40	3.4	406,250	2.37
2.82 - 4.15	242,750	3.42	3.8	68,688	3.06
4.85 - 6.82	1,423,500	5.80	4.6	-	-
1.87 - 6.82	2,818,750	4.21	4.0	474,938	2.47

Effective January 1, 2002, Canadian generally accepted accounting principles require disclosure of the impact on net earnings using the fair value method for stock options granted on or after January 1, 2002. If the fair value method had been used, the Company’s net earnings and net earnings per share for the year ended December 31, 2002 would approximate the following pro forma amounts:

	December 31, 2002
Compensation costs (\$ thousands)	
Net earnings:	
As reported	3,444
Pro forma	3,043
Net earnings per share:	
Basic	
As reported	0.13
Pro forma	0.12
Diluted	
As reported	0.13
Pro forma	0.11

The fair value of each Common Share option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

Risk free interest rate (%)	4.60
Expected life (years)	4.00
Expected volatility (%)	31

Earnings and Cash Flow per Share

The following table summarizes the common shares used in calculating net earnings and cash flow per Common Share.

Weighted Average Common Shares	2002	2001	2000
Basic	25,880,304	18,202,595	19,316,807
Diluted	27,458,571	18,979,720	20,569,743

Earnings and cash flow per share are calculated using the weighted average number of Common Shares and Class B Shares outstanding during the period. The Common Shares and Class B Shares are considered in aggregate due to the equal participation rights of these shares. At December 31, 2001, the conversion ratio of 2.58 Common Shares for each Class B Share was used to convert the Class B Shares to Common Shares for the purposes of determining the weighted average number of shares for basic per share calculations (see Conversion of Class B Shares above). The reconciling items between the basic and diluted weighted average common shares are outstanding stock options and warrants.

6.
TAXES

Tax Expense

The combined provision for taxes in the consolidated statement of earnings and retained earnings reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

(\$ thousands)	2002	2001	2000
Net income before taxes	7,483	9,661	11,049
Statutory income tax rate	42.9%	43.3%	44.6%
Expected income taxes	3,210	4,183	4,928
Add (deduct):			
Non-deductible crown charges (net of Alberta Royalty Tax Credit)	3,045	2,115	2,272
Resource allowance	(3,196)	(2,499)	(2,485)
Capital taxes	658	482	534
Other	322	(275)	(70)
	4,039	4,006	5,179

Future Income Taxes

The future income taxes liability at December 31 is comprised of the tax effect of temporary differences as follows:

(\$ thousands)	2002	2001
Property, plant and equipment	29,488	14,030
Site restoration and abandonment	(828)	(546)
Commodity sales contracts	(1,189)	-
Loss carry-forward	(1,626)	-
Share issue costs	(759)	(309)
Attributed Canadian Royalty Income	(561)	-
	24,525	13,175

As at December 31, 2002, the Company has tax pools of approximately \$96.9 million (2001 - \$43.5 million) available for deduction against future taxable income, including, \$3.7 million (2001 - nil) in unused losses that will expire in 2009.

7.
SUPPLEMENTAL
CASH FLOW
INFORMATION

Changes in Non-Cash Working Capital

(\$ thousands)	2002	2001	2000
Accounts receivable	(3,530)	(2,267)	(3,085)
Prepaid expense and deposits	(1,649)	(198)	(233)
Accounts payable and accrued liabilities	8,542	(3,682)	5,952
	3,363	(6,147)	2,634

Cash Interest and Taxes Paid

(\$ thousands)	2002	2001	2000
Cash interest	1,409	1,219	957
Cash income and other taxes	856	3,766	384

8.
FINANCIAL
INSTRUMENTS

Fair Value of Financial Instruments

The Company’s financial instruments recognized in the balance sheet consist of accounts receivable, accounts payable and bank debt. The fair value of these financial instruments approximate their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank debt.

Credit Risk

The Company’s accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. The Company sells substantially all of its production to six primary purchasers under normal industry sale and payment terms. The Company may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. The Company mitigates this risk by entering into transactions with highly rated major financial institutions.

Commodity Price Contracts

The Company is party to certain off-balance sheet derivative financial instruments, including crude oil and natural gas swap contracts. The Company enters into these contracts for the purpose of protecting its future earnings and cash flow from operations from the volatility of crude oil and natural gas commodity prices. The swap contracts reduce the fluctuations in petroleum and natural gas revenues by locking in fixed forward prices on a portion of the Company’s crude oil and natural gas production.

The Company has entered into several short-term arrangements for both crude oil and natural gas. For the year ended December 31, 2002, the Company realized a net loss of \$1.4 million (2001 - 0.1 million, 2000 - \$0.6 million) on its crude oil and natural gas price risk management.

Contracts outstanding in respect to financial instruments as at December 31, 2002 were as follows:

Contract	Volume	Pricing Point	Strike Price	Cost/Premium	Term
Crude Oil					
Put option	300 bbl/d	WTI	US\$23.00	US\$0.64/bbl	Jan 01/03 - Mar 31/03
Put option	800 bbl/d	WTI	US\$21.00	US\$1.26/bbl	Apr 01/03 - Jun 30/03
Put option	800 bbl/d	WTI	US\$21.00	US\$1.05/bbl	Jul 01/03 - Sep 30/03
Call option	1,000 bbl/d	WTI	US\$27.00	US\$1.10/bbl	Jan 01/03 - Mar 31/03
Costless collar ⁽¹⁾	200 bbl/d	WTI	US\$23.35 - US\$30.00	n/a	Jan 01/03 - Mar 31/03
Costless collar ⁽¹⁾	300 bbl/d	WTI	US\$21.00 - US\$29.75	n/a	Jan 01/03 - Mar 31/03
Natural Gas					
Put option	10,000 gj/d	AECO	CDN\$4.00	CDN\$0.155/gj	Jan 01/03 - Mar 31/03
Put option	3,000 mmbtu/d	SUMAS	US\$3.85	US\$0.215/mmbtu	Jan 01/03 - Oct 31/03
Put option	5,000 gj/d	AECO	CDN\$4.00	CDN\$0.265/gj	Apr 01/03 - Oct 31/03
Costless collar ⁽¹⁾	5,000 gj/d	AECO	CDN\$4.00 - CDN\$6.62	n/a	Apr 01/03 - Oct 31/03
Costless collar ^(1,2)	5,000 gj/d	AECO	CDN\$4.90 - CDN\$8.00	n/a	Apr 01/03 - Jun 30/03
Costless collar ^(1,2)	2,000 gj/d	AECO	CDN\$5.00 - CDN\$8.00	n/a	Jul 01/03 - Oct 31/03

(1) costless collar strike price indicates minimum floor and maximum ceiling
(2) transactions entered into after December 31, 2002 are not reflected in estimated fair market values below.

At December 31, 2002 the estimated fair value of the above financial instrument transactions, with the exception of the crude oil call option, were as follows:

(\$ thousands receivable (payable))	
Crude oil options*	15
Natural gas options*	(275)

* based on Canadian dollar exchange rate of 1.5796 per US dollar

To recover the amount paid for crude oil put options, the Company sold a crude oil call option. The change in the fair value of the crude oil call option outstanding at year-end was \$0.4 million and recorded as a non cash charge to petroleum and natural gas revenue at December 31, 2002 as it did not qualify for hedge accounting treatment.

The above estimated fair values are based on the market value of these instruments as at year-end and represent the amounts the Company would have received or paid to terminate the contracts at year-end.

Commodity Sales Contract

The following physical gas sales contract was outstanding at December 31, 2002. This contract was acquired in conjunction with the Campion acquisition at which time the fair value of the contract was a liability of \$4.1 million. This value was recorded as a liability on June 3, 2002, the effective date of the acquisition, and is being amortized over the life of the contract. At December 31, 2002 the remaining liability was \$3.7 million.

Volume	Pricing Point	Progress Price	Term
1,000 gj/d	AECO	\$1.91/gj in 2002 escalating at 2.5% annually	Jun 1/97 - Oct 31/08

2002 FINANCIAL HIGHLIGHTS

	Three months ended 2002				Annual
(\$ thousands except per share amounts)	March 31	June 30	Sept. 30	Dec 31	2002
Income Statement					
Petroleum and natural gas sales	6,099	7,905	10,171	21,645	45,820
Cash flow from operations	3,349	4,064	4,609	11,999	24,020
Per share - basic	0.15	0.17	0.17	0.39	0.93
Per share - diluted	0.14	0.16	0.17	0.37	0.87
Net earnings	160	357	152	2,775	3,444
Per share - basic	0.01	0.02	0.01	0.09	0.13
Per share - diluted	0.01	0.01	0.01	0.08	0.13
Balance Sheet					
Capital spending					
Land acquisitions and retention	424	1,218	1,201	2,628	5,471
Geological and geophysical	475	287	596	1,050	2,408
Drilling and completions	2,371	2,018	5,676	5,467	15,532
Equipping and facilities	1,506	935	1,803	2,072	6,316
Net property acquisitions (dispositions)	74	64	2,131	27,577	29,846
Acquisition of Campion Resources Ltd.	-	40,791	-	-	40,791
Corporate assets	137	325	62	112	636
	4,987	45,638	11,469	38,906	101,000
Total debt					
Bank debt	15,733	40,640	40,238	43,386	43,386
Working capital deficiency (surplus)	2,789	(3,660)	3,502	3,933	3,933
	18,522	36,980	43,740	47,319	47,319
Shareholders' equity	41,660	62,044	62,439	89,553	89,553
Common Share Information <i>(thousands except where otherwise stated)</i>					
Shares outstanding at end of period					
Common	22,585	26,315	26,430	30,912	30,912
Weighted average shares outstanding for the period					
Basic	22,505	23,728	26,336	30,909	25,880
Diluted	23,974	25,290	27,811	32,717	27,459
Volume traded	6,092	2,680	2,856	2,878	14,506
Common share price (\$)					
High	6.15	6.50	6.10	8.30	8.30
Low	3.86	5.00	4.65	5.10	3.86
Closing	5.90	5.25	5.95	8.00	8.00

2002 OPERATIONAL HIGHLIGHTS

	Three months ended 2002				Annual
	March 31	June 30	Sept. 30	Dec 31	2002
Production					
Natural gas (mcf/d)	8,083	11,300	17,488	28,205	16,327
Crude oil (bbl/d)	1,670	1,591	1,623	2,055	1,736
Natural gas liquids (bbl/d)	40	79	221	340	171
Total (boe/d) (6:1)	3,057	3,553	4,759	7,096	4,628
Total (boe/d) (10:1)	2,518	2,800	3,592	5,216	3,539
Pricing					
Natural gas (before hedging) (\$/mcf)	3.09	3.22	2.85	5.33	4.06
Hedging (\$/mcf)	0.06	-	(0.11)	(0.01)	0.04
Amortization of commodity sales contract (\$/mcf)	-	0.16	0.36	0.09	0.07
Natural gas (after hedging) (\$/mcf)	3.15	3.38	3.10	5.41	4.17
Crude oil (before hedging) (\$/bbl)	25.96	34.11	37.55	36.54	33.72
Hedging (\$/bbl)	(1.23)	(5.10)	(7.13)	(0.01)	(3.14)
Unrealized loss on financial instrument (\$/bbl)	-	-	-	(1.97)	(0.59)
Crude oil (after hedging) (\$/bbl)	24.73	29.01	30.42	34.56	29.99
Natural gas liquids (\$/bbl)	24.71	31.30	31.14	33.78	32.08
Selected Highlights (\$boe)					
Weighted average sales price	22.17	24.45	23.24	33.16	27.13
Royalties, net of ARTC	3.66	3.11	4.79	7.53	5.34
Production expenses	4.34	4.85	4.80	5.18	4.88
Netbacks	14.17	16.49	13.65	20.67	16.87
General and administrative	1.10	2.12	1.39	1.79	1.64
Depletion and depreciation	10.62	10.49	10.07	9.36	9.97
Net earnings	0.58	1.10	0.35	4.25	2.04
Gross Drilling Results					
Natural gas	2	2	6	6	16
Crude oil	-	-	1	-	1
Dry	-	1	2	1	4
	2	3	9	7	21
Success rate (%)	100	67	78	86	81
Net Drilling Results					
Natural gas	0.4	2	4.8	5.2	12.4
Crude oil	-	-	0.4	-	0.4
Dry	-	1	1.4	0.5	2.9
	0.4	3	6.6	5.7	15.7
Success rate (%)	100	67	79	91	82

2001 FINANCIAL HIGHLIGHTS

	Three months ended 2001				Annual
<i>(\$ thousands except per share amounts)</i>	March 31	June 30	Sept. 30	Dec 31	2001
Income Statement					
Petroleum and natural gas sales	10,113	9,508	7,457	6,124	33,202
Cash flow from operations	5,372	4,682	3,954	3,908	17,916
Per share - basic	0.30	0.25	0.22	0.20	0.98
Per share - diluted	0.28	0.25	0.22	0.19	0.94
Net earnings	2,635	2,450	1,061	(491)	5,655
Per share - basic	0.15	0.13	0.06	(0.03)	0.31
Per share - diluted	0.14	0.13	0.06	(0.02)	0.30
Balance Sheet					
Capital spending					
Land acquisitions and retention	257	305	311	135	1,008
Geological and geophysical	509	362	178	274	1,323
Drilling and completions	4,724	1,297	3,705	2,176	11,902
Equipping and facilities	1,788	362	1,360	706	4,216
Net property acquisitions (dispositions)	(76)	187	1,315	5,519	6,945
Corporate assets	5	3	-	17	25
	7,207	2,516	6,869	8,827	25,419
Total debt					
Bank debt	18,325	28,803	25,986	17,976	17,976
Working capital deficiency (surplus)	5,776	(6,895)	115	(562)	(562)
	24,101	21,908	26,101	17,414	17,414
Shareholders' equity	26,095	28,545	28,355	40,964	40,964
Common Share Information <i>(thousands except where otherwise stated)</i>					
Shares outstanding at end of period					
Common	14,909	14,909	17,494	22,087	22,087
Class B shares	1,170	1,170	-	-	-
Weighted average shares outstanding for the period					
Basic	18,063	18,402	17,734	19,170	18,203
Diluted	19,268	19,056	18,368	20,180	18,980
Volume traded	461	504	589	3,354	4,908
Common share price (\$)					
High	3.75	4.25	3.35	4.05	4.25
Low	2.45	3.30	2.49	2.30	2.30
Closing	3.75	3.35	2.49	3.95	3.95

2001 OPERATIONAL HIGHLIGHTS

	Three months ended 2001				Annual
	March 31	June 30	Sept. 30	Dec 31	2001
Production					
Natural gas (mcf/d)	4,635	7,735	7,949	7,745	7,027
Crude oil (bbl/d)	1,852	1,696	1,796	1,906	1,812
Natural gas liquids (bbl/d)	43	32	35	37	37
Total (boe/d) (6:1)	2,667	3,017	3,156	3,233	3,020
Total (boe/d) (10:1)	2,358	2,502	2,626	2,717	2,551
Pricing					
Natural gas (before hedging) (\$/mcf)	8.89	5.64	2.77	2.90	4.59
Hedging (\$/mcf)	(0.09)	-	-	-	(0.02)
Natural gas (after hedging) (\$/mcf)	8.80	5.64	2.77	2.90	4.57
Crude oil (before hedging) (\$/bbl)	37.05	36.42	32.27	22.44	31.83
Hedging (\$/bbl)	0.56	(1.27)	-	0.24	(0.09)
Crude oil (after hedging) (\$/bbl)	37.61	35.15	32.27	22.68	31.74
Natural gas liquids (\$/bbl)	45.27	37.50	31.59	24.86	35.30
Selected Highlights (\$boe)					
Weighted average sales price	42.13	34.63	25.68	20.59	30.12
Royalties, net of ARTC	9.50	6.58	3.93	3.20	5.61
Production expenses	4.68	4.65	4.53	4.60	4.61
Netbacks	27.94	23.40	17.22	12.79	19.90
General and administrative	0.18	0.82	1.04	1.60	0.95
Depletion and depreciation	8.11	8.35	8.82	10.67	9.05
Net earnings	10.98	8.92	3.65	(1.65)	5.13
Gross Drilling Results					
Natural gas	6	-	-	-	6
Crude oil	2	-	8	3	13
Dry	3	-	1	-	4
	11	-	9	3	23
Success rate (%)	73	-	89	100	83
Net Drilling Results					
Natural gas	1.4	-	-	-	1.4
Crude oil	1.1	-	5.4	2.8	9.3
Dry	0.8	-	1.0	-	1.8
	3.3	-	6.4	2.8	12.5
Success rate (%)	76	-	84	100	86

HISTORICAL PERSPECTIVE

Year ended December 31

<i>(\$ thousands except per share data)</i>	2002	2001	2000	1999	1998	1997
Financial						
Petroleum and natural gas sales	45,820	33,202	29,593	11,162	4,476	81
Cash flow from operations	24,020	17,916	14,604	5,367	2,219	34
Per share - basic	0.93	0.98	0.76	0.29	0.19	0.01
Per share - diluted	0.87	0.94	0.71	0.28	0.14	0.01
Net earnings (loss)	3,444	5,655	5,870	1,072	321	6
Per share - basic	0.13	0.31	0.30	0.06	0.02	0.00
Per share - diluted	0.13	0.30	0.29	0.06	0.02	0.00
Net capital expenditures	60,210	25,419	23,494	18,802	15,714	9,146
Total assets	186,963	81,935	65,325	41,871	26,962	17,490
Working capital deficiency (surplus)	3,933	(316)	5,517	2,951	2,681	(7,410)
Long term debt	43,386	17,976	16,409	9,418	-	-
Shareholders' equity	89,553	40,964	23,800	18,613	15,878	15,983
Operating						
Production						
Natural gas <i>(mcf/d)</i>	16,327	7,027	5,718	3,784	-	-
Crude oil and NGL <i>(bbls/d)</i>	1,906	1,849	1,303	803	655	366
Total <i>(boe/d) (10:1)</i>	3,539	2,552	1,875	1,181	655	366
Total <i>(boe/d) (6:1)</i>	4,628	3,020	2,256	1,434	655	366
Pricing						
Natural gas <i>(\$/mcf)</i>	4.17	4.57	4.92	2.91	-	-
Crude oil and natural Gas liquids <i>(\$/bbl)</i>	30.17	31.81	40.44	24.38	18.10	24.68
Proven reserves						
Natural gas <i>(mmcf)</i>	71,645	21,581	21,025	19,232	10,033	-
Crude oil and NGL <i>(mbbls)</i>	4,871	3,958	4,425	3,081	2,411	895
Present value <i>(\$ millions discounted at 12% before tax)</i>	155	71	81	44	-	-
Undeveloped land						
Gross acres	235,000	149,000	257,000	241,000	209,000	201,000
Net acres	340,000	97,000	194,000	199,000	187,000	180,000
Share Information <i>(thousands)</i>						
Common share price <i>(\$)</i>						
High	8.30	4.25	3.06	3.10	3.00	N/A
Low	3.86	2.30	1.75	1.50	1.40	N/A
Closing	8.00	3.95	2.75	2.50	3.00	N/A
Volume traded	14,506	4,908	1,493	545	234	N/A
Shares outstanding at year end						
Common shares	30,912	22,087	15,029	14,922	13,602	11,602
Class B shares	-	-	1,170	1,171	1,171	1,171
Weighted average common shares						
Basic	25,880	18,203	19,317	18,414	15,626	4,481
Diluted	27,459	18,980	20,570	19,107	19,775	4,481

SHAREHOLDER INFORMATION

Annual Meeting

The Annual and Special General Meeting of Shareholders will be held on Tuesday, May 14, 2003 at 10:00 a.m. in the Metropolitan Centre, 333 - 4th Avenue S.W., Calgary, Alberta

Annual Information Form

Copies of the Annual Information Form are available to shareholders upon request.

www.progressenergy.com

Shareholders and interested investors are encouraged to visit our web site. Historical public disclosure documents (in PDF format), latest roadshow material, press releases are all available. Filings also available at: www.sedar.com

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Investor Relations

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Corporate Governance

A system of corporate governance for the Corporation has been established to provide the Board of Directors, management and shareholders of the Corporation with effective governance. A more detailed discussion of corporate governance is available in the Information Circular for the Annual and Special General Meeting of Shareholders.

Stock Exchange Listing

The Toronto Stock Exchange
Symbol: PGX

Estimated Release Date of Quarterly Results

First Quarter	May 8, 2003
Second Quarter	July 31, 2003
Third Quarter	October 30, 2003

Share Volume and Share Price (January 1998 to February 2003)

(number of shares)



CORPORATE INFORMATION

Directors

John M. Stewart ⁽¹⁾
Chairman
Progress Energy Ltd.
Vice Chairman
ARC Financial Corporation
Calgary, Alberta

David D. Johnson
President and
Chief Executive Officer
Progress Energy Ltd.
Calgary, Alberta

John A. Brussa ⁽¹⁾
Partner
Burnet, Duckworth and Palmer
Calgary, Alberta

Frederic C. Coles ⁽³⁾
President
Menehune Resources Ltd.
Calgary, Alberta

Gary E. Perron ⁽¹⁾⁽²⁾
Managing Director and
Senior Vice President
BMO Nesbitt Burns
Calgary, Alberta

Terrance D. Svarich ⁽²⁾⁽³⁾
President
Devsun Ltd.
Calgary, Alberta

Officers

David D. Johnson
President and
Chief Executive Officer

Steven A. Allaire
Vice President Finance and
Chief Financial Officer and
Corporate Secretary

Michael R. Culbert
Vice President Marketing and
Business Development

Edward J. Kalthoff
Vice President Land

William J. Lewington
Controller

Neil H. Samis
Vice President Production

Daniel C. Topolinsky
Vice President Exploration

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Corporate Banking
Canada Trust Tower
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Solicitor

Burnet, Duckworth & Palmer
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Auditor

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Consulting Engineer

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⁽¹⁾ Member of Audit Committee

⁽²⁾ Member of Compensation Committee

⁽³⁾ Member of Reserves Committee

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